PB82-249350

Environmental Assessment of Stationary Source NOx Control Technologies

Acurex Corp.
Mountain View, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

May 82

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

EPA-600/7-82-034
May 1982

EPA

Research and Development

PB82-249350

ENVIRONMENTAL ASSESSMENT OF STATIONARY SOURCE NO_X CONTROL TECHNOLOGIES

(Final Report)

Prepared for

Office of Air Quality Planning and Standards

Prepared by

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-82-034	2.	3. RECIPIENT'S ACCESSION NO. PB82 249350
4. TITLE AND SUBTITLE Environmental Assessment of Stationary Source NO_x Control Technologies: Final Report		5. REPORT DATE May 1982
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) L. R. Waterland, K. J. Lim, E. B. Higginbotham, R. M. Evans, and H. B. Mason		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Acurex Corporation 485 Clyde Avenue Mountain View, California 94042		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-02-2160
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 6/76-9/79
		14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Joshua S. Bowen, Mail Drop 65, 919/541-2470.

16. ABSTRACT The report summarizes results of a 3-year evaluation of combustion modification controls for emissions of NOx and other pollutants from stationary combustion sources. Results include field tests of gaseous, liquid, and solid effluents from seven stationary sources; estimates of environmental effects of using combustion modification control; evaluation of NOx control reduction effectiveness, capital and operating costs, and operational impact for several levels of control; projection of control technology needs to the year 2000 for several scenarios of energy growth and environmental regulations; and inventories of nationwide stationary source emissions for major pollutants and emission projections to the year 2000. Three utility boilers, two industrial boilers, a gas turbine, and a low-emission residential heating system were tested. The utility boiler tests on two coal-fired systems and one oil-fired boiler, showed NOx emission level reductions of 30-43% using various combustion modification techniques; however, the same tests showed that other emissions were essentially unchanged. Similarly, tests on the other types of equipment showed that modifications to reduce NOx left emissions of other species unchanged or lower. In some cases, where emissions were increased, the environmental effect was counterbalanced by the beneficial effects of NO reduction.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Combustion Control	Stationary Sources	21B
Nitrogen Oxides	Combustion Modification	07B
Assessments	Environmental Assessments	14B
Boilers		13A
Gas Turbines		13G

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 337
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

EPA-600/7-82-034
MAY 1982

Acurex Final Report FR-80-57/EE

ENVIRONMENTAL ASSESSMENT OF STATIONARY SOURCE NO_x CONTROL TECHNOLOGIES -- FINAL REPORT

Acurex Project 7242

Contract 68-02-2160

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SECTION 1
INTRODUCTION AND SUMMARY

This report summarizes the results of a 3-year evaluation of combustion modification controls for emissions of NO_x and other pollutants from stationary combustion sources. Results include field tests of gaseous, liquid, and solid effluents from seven stationary combustion sources; estimates of environmental effects of using combustion modification control; evaluation of NO_x control reduction effectiveness, capital and operating costs, and operational impact for several levels of control; projections of control technology needs to the year 2000 for several scenarios of energy growth and environmental regulations; and inventories of nationwide stationary source emissions for major pollutants. Three utility boilers, two industrial boilers, a gas turbine, and a low-emission residential heating system were tested. The utility boiler tests on two coal-fired systems and one oil-fired boiler showed NO_x emission level reductions of 30 to 40 percent using various combustion modification techniques; however, the same tests showed that other emissions were essentially unchanged. Similarly, tests on the other types of equipment showed that modifications to reduce NO_x left emissions of other species unchanged or lower. In some cases, where emissions were increased, the environmental effect was counterbalanced by the beneficial effects of NO reduction.

1.1 INTRODUCTION

In 1975, the Environmental Protection Agency's Industrial Environmental Research Laboratory (IERL) started a major program for the environmental assessment of energy systems and industrial processes. The purpose of the assessments was to detect and quantify potential environmental problems with the systems or processes and to identify control measures that could reduce the environmental problems found. This information was needed by EPA and others to establish R&D priorities, to support standards setting activities by regulatory groups, and to help guide the development of environmentally acceptable energy systems. The core of the environmental assessment program is a series of environmental assessments directed at specific processes such as fluidized bed combustion and low-Btu gasification. To attain a uniformity of approach and consistency of results in these individual assessments, a parallel effort was directed at developing testing and analysis techniques and toward refining environmental assessment methodologies for use by all environmental assessment (EA) contractors of IERL. From this effort, a first generation methodology was formulated which specifies procedures for chemical sampling and analysis, biological assays, health and ecological effects estimation, and impact severity analysis.

The environmental assessments of stationary conventional combustion sources occupied a key part of the overall environmental assessment program. A major component of this effort was the "Environmental Assessment and Systems Analysis of Combustion Modification Technology for NO_x Control" (NO_x EA). The NO_x EA was initiated by IERL-RTP's (Research Triangle Park) Combustion Research Branch in June 1976 to support the overall EA programs for stationary combustion sources with combustion modification techniques to control NO_x or other pollutants amenable to control through combustion process modification.

At the idea's inception, NO_x control technology was a high priority concern within EPA because numerous projections indicated that NO_x environmental goals could not be met in the 1980's and 1990's without increased control of new and/or existing stationary combustion sources. Currently, large combustion sources are controlled to a moderate level as part of existing regulatory programs. However, increased control may be needed for two reasons. First, stationary source NO_x emissions, if uncontrolled, are projected to increase by a factor of two or more by the year 2000 due to industrial growth and the increasing use of coal in both new and existing sources. Second, the 1977 Clean Air Act Amendments established a number of regulatory provisions to add new control regulations, or to increase the stringency of existing regulations. Additional possible regulatory activity such as requirements for emission offsets in nonattainment areas, prevention of significant deterioration and prevention of visibility degradation could all require implementation of stringent stationary source NO_x controls on new or existing sources. With this prospect of expanding NO_x control applications, there is a clear need to determine environmental impacts of NO_x controls and to identify the best control options for meeting current and future NO_x environmental goals.

In this context, the NO_x EA program was created to answer the following questions:

- What are the environmental side effects of NO_x control?
- Which sources/fuels/effluent streams/pollutant species/NO_x controls are a potential problem?
- What are NO_x control effects on equipment operation and maintenance, and on capital cost?
- What are the likely emission control levels that will be necessary in the future, and which are the preferred technologies to meet these levels?

To address these questions, the objectives of NO_x EA were set as follows:

- Determine multimedia environmental stresses from stationary combustion sources and from combustion modification technology applied to these sources
- Develop and document control application guidelines to minimize these stresses
- Identify stationary source and combustion modification R&D priorities
- Support environmental assessment methodology development
- Disseminate program results to potential users

The program approach to meet these objectives encompassed six major tasks as illustrated in Figure 1-1. Here, the rectangles denote key subtasks while outputs are represented by ovals. The four major tasks at the left of Figure 1-1 support the first program objective. Section 2 of this report presents the source/control priorities set from the emissions characterization (Task B1) and summarizes the results of the experimental testing (Task B3) conducted on the basis of these priorities. Section 3 summarizes the impact severity estimates from source analysis modeling (D) using impacts and standards (Task B2) criteria compiled during the program. This information establishes the estimated environmental side effects of NO_x controls for the major conventional sources and controls which were tested

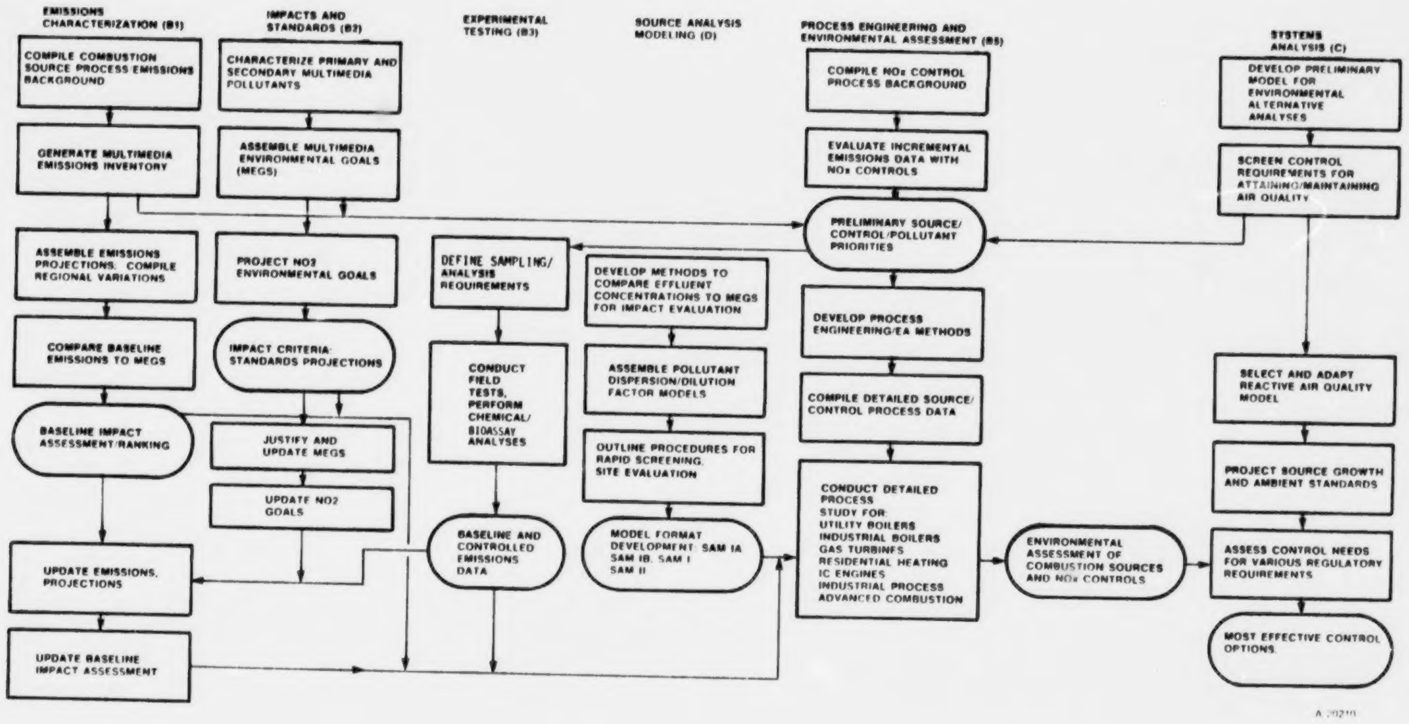
EMISSIONS CHARACTERIZATION (B1)
COMPILE COMBUSTION SOURCE PROCESS EMISSIONS BACKGROUND
GENERATE MULTIMEDIA EMISSIONS INVENTORY
ASSEMBLE EMISSIONS PROJECTIONS; COMPILE REGIONAL VARIATIONS
COMPARE BASELINE EMISSIONS TO MEGS
BASELINE IMPACT ASSESSMENT/RANKING
UPDATE EMISSIONS, PROJECTIONS
UPDATE BASELINE IMPACT ASSESSMENT
IMPACTS AND STANDARDS (B2)
CHARACTERIZE PRIMARY AND SECONDARY MULTIMEDIA POLLUTANTS
ASSEMBLE MULTIMEDIA ENVIRONMENTAL GOALS (MEGS)
PROJECT NO2 ENVIRONMENTAL GOALS
IMPACT CRITERIA: STANDARDS PROJECTIONS
JUSTIFY AND UPDATE MEGS
UPDATE NO2 GOALS
EXPERIMENTAL TESTING (B3)
DEFINE SAMPLING/ ANALYSIS REQUIREMENTS
CONDUCT FIELD TESTS, PERFORM CHEMICAL/ BIOASSAY ANALYSES
BASELINE AND CONTROLLED EMISSIONS DATA
SOURCE ANALYSIS MODELING (D)
DEVELOP METHODS TO COMPARE EFFLUENT CONCENTRATIONS TO MEGS FOR IMPACT EVALUATION
ASSEMBLE POLLUTANT DISPERSION/DILUTION FACTOR MODELS
OUTLINE PROCEDURES FOR RAPID SCREENING, SITE EVALUATION
MODEL FORMAT DEVELOPMENT: SAM IA SAM IB, SAM I SAM II
PROCESS ENGINEERING AND ENVIRONMENTAL ASSESSMENT (B5)
COMPILE NOx CONTROL PROCESS BACKGROUND
EVALUATE INCREMENTAL EMISSIONS DATA WITH NOx CONTROLS
PRELIMINARY SOURCE/ CONTROL/POLLUTANT PRIORITIES
DEVELOP PROCESS ENGINEERING/EA METHODS
COMPILE DETAILED SOURCE/ CONTROL PROCESS DATA
CONDUCT DETAILED PROCESS STUDY FOR: UTILITY BOILERS INDUSTRIAL BOILERS GAS TURBINES RESIDENTIAL HEATING IC ENGINES INDUSTRIAL PROCESS ADVANCED COMBUSTION
ENVIRONMENTAL ASSESSMENT OF COMBUSTION SOURCES AND NOx CONTROLS
SYSTEMS ANALYSIS (C)
DEVELOP PRELIMINARY MODEL FOR ENVIRONMENTAL ALTERNATIVE ANALYSES
SCREEN CONTROL REQUIREMENTS FOR ATTAINING/MAINTAINING AIR QUALITY
SELECT AND ADAPT REACTIVE AIR QUALITY MODEL
PROJECT SOURCE GROWTH AND AMBIENT STANDARDS
ASSESS CONTROL NEEDS FOR VARIOUS REGULATORY REQUIREMENTS
MOST EFFECTIVE CONTROL OPTIONS
A 20210

Figure 1-1. NO_x EA Program Approach

during the 3-year program. These results are augmented in Section 4 with control costs, effectiveness, and operational impact estimates from the process engineering and environmental assessment (Task B5) study performed in support of the second program objective. Section 5 summarizes the systems analysis study (Task C) to estimate the extent of NO_x control applications needed to attain and maintain NO_x regulations now and to the year 2000. Finally, Section 6 brings together the source/control information from Sections 2 through 4 to evaluate which are the most effective control options to meet the requirements identified in Section 5 and satisfy the third program objective. This report focuses on the major results and conclusions of the program. Further details on the approach and results can be found in a series of special reports generated within the program and listed in Appendix A. These reports also contain results from the methodology and technology transfer support functions, objectives 4 and 5.

1.2 SUMMARY

The five major categories of stationary sources of oxides of nitrogen are utility boilers, industrial boilers, internal combustion engines, gas turbines, and residential heating systems. These categories, together with industrial processes and minor sources, emitted 10.5×10^9 kg (11.6 million tons) of NO_x (NO_2 basis) in 1977, approximately equaling the mobile source loading. In the NO_x EA these five source categories were subjected to a 3-year environmental assessment involving multimedia source sampling and analysis, NO_x control process engineering, and NO_x air quality/regulatory evaluations.

Environmental assessment field testing was conducted on seven sources in these categories. Based on priorities set during the final year of the program, the following equipment was selected for testing: Kingston unit 6, a 180 MW coal-fired utility boiler; Crist unit 7, a 500-MW coal-fired utility boiler; Moss Landing unit 6, a 740-MW oil-fired utility boiler; Site A, a 38 kg/s stoker coal-fired industrial boiler; Site B, a 25-kg/s stoker coal-fired industrial boiler; T. H. Wharton unit 52, a 60-MW oil-fired gas turbine; and a Blueray low-emission oil-fired residential heating system. Table 1-1 summarizes the key aspects of these seven field tests.

Table 1-1. NO_x EA Field Test Program

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Coal-fired Utility Boiler	Kingston #6; 180 MW tangential; twin furnace, 12 burners/furnace, 3 elevations; cyclone, 2 ESP's for particulate control	Baseline Biased Firing (2) BOOS (2)	Continuous NOx, SO_2, CO, CO_2, O_2 Inlet to 1st ESP: -- SASS -- Method 5 -- Method 8 -- Gas grab (C_1-C_6 HC) Outlet of 1st ESP -- SASS -- Method 5 -- Method 8 -- Gas Grab (C_1-C_6 HC) Bottom ash Hopper ash (1st ESP, cyclone) Fuel Operating data	TVA
Coal-fired Utility Boiler	Crist #7; 500 MW opposed wall-fired; 24 burners, 3 elevations; ESP for particulate control	Baseline BOOS (2)	Continuous NO_x, CO CO_2, O_2 ESP inlet -- SASS -- Method 5 -- Method 8 -- Gas grab (C_1-C_6 HC) ESP Outlet -- SASS -- Method 5 -- Method 8 -- Gas Grab (C_1-C_6 HC) Bottom ash ESP hopper ash Fuel Operating data Bioassay	Exxon

Key to acronyms:

BOOS:	Staged combustion technique with burners out of service
ESP:	Electrostatic precipitator
FGR:	Flue gas recirculation through burner windbox
LEA:	Low excess air firing
OFA:	Staged combustion with overfire air injection
SASS:	Source assessment sampling system for organic and inorganic emission collection and measurement

Table 1-1. (Continued)

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Oil-fired Utility Boiler	Moss Landing #6; 740 MW opposed wall-fired; 48 burners, 6 elevations	Baseline FGR FGR + OFA	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 -- Gas grab (C_1-C_6 HC) Fuel Operating data Bioassay	None
Coal-fired Industrial Boiler	Traveling grate spreader stoker, 38 kg/s (300,000 lb steam/hr)	Baseline LEA + high OFA	Continuous NO_x, CO CO_2, O_2 Boiler exit: -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) ESP outlet -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) Bottom ash Cyclone hopper ash Fuel Operating data	KVB

Key to acronyms:

BOOS:	Staged combustion technique with burners out of service
ESP:	Electrostatic precipitator
FGR:	Flue gas recirculation through burner windbox
LEA:	Low excess air firing
OFA:	Staged combustion with overfire air injection
SASS:	Source assessment sampling system for organic and inorganic emission collection and measurement

Table 1-1. (Concluded)

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Coal-fired Industrial Boiler	Traveling grate spreader stoker, 25 kg/s (200,000 lb steam/hr) ESP for particulate control	Baseline LEA	Continuous NO_x, CO CO_2, O_2 Boiler exit: -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) ESP Outlet -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) Bottom ash ESP hopper ash Fuel Operating data Bioassay	KVB
Oil-fired Gas turbine	T. H. Wharton Station. 60 MW GE MS 7001 C machine	Baseline maximum water injection	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 Fuel Water Operating data Bioassay	General Electric
Oil-fired Residential Heating Unit	Blueray low NO_x furnace, Medford, New York	Continuous cycling	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 Fuel	EPA/IERL-RTP

Key to acronyms:

BOOS:	Staged combustion technique with burners out of service
ESP:	Electrostatic precipitator
FGR:	Flue gas recirculation through burner windbox
LEA:	Low excess air firing
OFA:	Staged combustion with overfire air injection
SASS:	Source assessment sampling system for organic and inorganic emission collection and measurement

Tests results were evaluated using an index of potential health hazard, termed discharge severity (DS). The DS was defined by the environmental assessment protocol as (Reference 1-1):

$$DS_i = \frac{\text{Concentration of pollutant i in effluent stream}}{\text{Discharge multimedia environmental goal of pollutant i}}$$

to aid in screening pollutants of potential environmental concern. The discharge multimedia environmental goal (DMEG) is the maximum pollutant discharge concentration desirable in discharge streams to preclude adverse effects to human health. DMEG concentrations have been defined by IERL-RTP (References 1-2 and 1-3). A stream total discharge severity is also defined as the sum of the DS's calculated for the discharge stream.

Table 1-2 and 1-3 present a summary of the field test results for the flue gas and ash streams in terms of the discharge severity. The tables list pollutant components with DS values greater than 1 for each source tested, with an indication of the magnitude of the discharge severity for each component for each source.

From Table 1-2, it is apparent that SO_2 and NO_x emissions present the greatest potential hazard from all the combustion sources tested. The DS for these is especially high from coal-fired sources. Other species with high discharge severity in most tests included CO_2, CO, As, and SO_3 (vapor phase). The only organic emissions of potential concern noted were those of carboxylic acids. Several other trace element species and condensed sulfate were flagged of concern in several tests, though these were not universally noted.

Table 1-3 shows that the potentially most hazardous species in the ash streams from coal-fired sources were iron and manganese, followed by chromium, nickel, beryllium, and barium. Interestingly, lead levels were high only in particle collector ash streams, particularly the ESP hopper ash, suggesting that lead partitions to potentially hazardous levels on passage through a boiler.

Table 1-4 compares the stream DS's. The stream DS's for a given source are generally within an order of magnitude of each other. In general, changes in flue gas discharge severity due to NO_x control are less

Table 1-2. Discharge Severity Summary for Flue Gas

Component	DS Level[a]						
	Kingston Unit 6	Crist Unit 7	Moss Landing Unit 6	Site A	Site B	T. H. Wharton Unit 52	Blueray Furnace
SO_2	+++	+++	++	++	++	+	+
NO_x	+++	+++	++	++	++	+	-
CO_2	++	++	++	-	++	+	-
As	++	++	+	+	++	+	-
SO_3 (vapor)	++	++	+	++	+	+	-
$CO_=$	+	++	+	+	+	-	+
SO_4 (condensed)	++	++	+	-	-	-	-
Fe	++	++	-	+	-	-	-
Carboxylic acids	-	+	+	+	-	-	+
Be	+	+	-	+	-	-	-
Co	+	+	+	-	-	-	-
Ba	+	+	-	-	-	-	-
B	-	-	+	+	-	-	-
Ti	-	+	-	+	-	-	-
Cu	+	-	+	-	-	-	-
Cd	-	-	-	+	-	+	-
Pb	-	-	-	+	-	-	-
Cl	+	-	-	-	-	-	-
U	-	-	+	-	-	-	-

[a] Key:
+++ denotes DS > 100
++ denotes DS > 10
+ denotes DS > 1
- denotes DS < 1 or species not measured

Table 1-3. Discharge Severity Summary for Ash Streams

Ash Stream	Component	DS Level[a]			
		Kingston Unit 6	Crist Unit 7	Site A	Site B
Bottom ash	Fe	-	+++	+++	++
	Mn	+	++	++	++
	Cr	+	+	-	+
	Ni	+	+	-	+
	Be	+	+	-	-
	Ba	+	-	-	-
	Tl	-	+	-	-
	Sn	-	-	+	-
Mechanical collector hopper ash	Fe	-	-[b]	++	+
	Mn	+	-	+	+
	Be	+	-	-	+
	Cr	+	-	-	+
	Ba	+	-	-	-
	Pb	-	-	-	+
	Ni	+	-	-	-
ESP hopper ash	Fe	-	+++	++	-
	Mn	+	++	++	-
	Be	+	+	-	++
	Ba	+	+	-	+
	Pb	+	+	+	-
	As	+	-	-	++
	Ni	+	+	+	-
	Cr	+	+	-	-
	$SO_4^=$	+	-	-	+
	Se	-	-	-	++
	Tl	-	+	-	-

[a] Key: +++ denotes DS > 100
++ denotes DS > 10
+ denotes DS > 1
- denotes DS < 1 or species not measured

[b] No mechanical collector at Crist Unit 7

Table 1-4. Total Stream Discharge Severity: Summary

	Flue Gas		Bottom Ash		Hopper Ash	
	Baseline	Low NO_x	Baseline	Low NO_x	Baseline	Low NO_x
Kingston Unit 6	640	580	18	16	23	23
Crist Unit 7	740	830	160	170	150	120
Moss Landing Unit 6	160	130	a	a	a	a
Site A	150	210	120	120	110	98
Site B	170	110	b	82	45	120
T. H. Wharton Unit 52	87	52	a	a	a	a
Blueray Furnace	70c	25	a	a	a	a

[a] Sample not applicable to this source

[b] Sample not analyzed

[c] Baseline residential furnace evaluation based on conventional furnace data (24, 25)

significant than those resulting from day-to-day variations in fuel composition (especially sulfur). When fuel variations are accounted for, NO_x control application either reduces flue gas discharge severity, or, at worst, does not increase it. This translates to a reduction, or, at worst, no increase in source total weighted discharge severity.

Since limited data existed on the effects of NO_x control on combustion source polycyclic organic matter (POM) and other organic emissions, and since several species in this pollutant class are quite hazardous, priority was given to obtaining data on these emissions in the field test program.

Table 1-5 shows total sampling train organic determination data for the tests performed. Infrared analysis of sample extracts showed the organic species in the samples were in the aliphatic hydrocarbon, ether, ester, aromatic, and carboxylic acid categories. The data in the table indicate, that as is the case for CO and HC emissions, emissions of these higher molecular weight organics remain relatively unchanged with NO_x control application. The seemingly high levels of organic compound emissions in the Blueray residential furnace test are primarily unburned fuel oil. This was a result of the "on-off" cycling of the furnace during the test.

Additional organic analyses were made with gas chromatography/mass spectrometry (GC/MS) speciation of at least 11 POM species and several organic priority pollutants (Table 1-6). Results showed that there is a marginal increase in POM emissions with NO_x control application. The emission levels were generally of the order of the detection level of the instrument. In the analyses for the organic priority pollutants, none of these species were found within the detection limits.

Bioassay testing of samples taken during the Crist Unit 7, Moss Landing Unit 6, Site B, and gas turbine lowest NO_x tests was performed in the test program. Table 1-7 summarizes results from all bioassay tests performed and notes the stream total discharge severity for the appropriate sample assayed. From the data presented in the table no significant correlation between stream discharge severity and bioassay test results is apparent. Most bioassays gave nondetectable toxicity responses which prevented determination of any correlation.

The conclusions evident from the field testing and analysis program are as follows:

Table 1-5. Effects of Controls Tested on Flue Gas Organic Emissions

Test	Fuel	Control[a]	Organic Emissions (mg/dscm)		
			Baseline	Intermediate NO_x	Low NO_x
Kingston Unit 6	Coal	BOOS	0.124	--	0.834
Crist Unit 7	Coal	BOOS	4.23	2.32	0.722
Moss Landing Unit 6	Residual and crude oil	FGR, BOOS/FGR	4.38	1.37	1.43
Stoker Site A	Coal	OFA	1.00	--	1.79
Stoker Site B	Coal	LEA	0.924	--	1.37
T.H. Wharton Unit 52	Distillate oil	WI	1.30	--	1.10
Blueray Furnace	Distillate oil	New design	0.7-12.1[b]	--	

[a] BOOS: Burners out of service;
FGR: Flue gas recirculation; OFA: High overfire air;
LEA: Low excess air; WI: Water injection

[b] Range of emissions from tests of conventional furnaces (Reference 1-4)

Table 1-6. Effects of Controls Tested on Flue Gas POM Species Emissions (μg/dscm)

POM Species	Crist Unit 7			Moss Landing Unit 6			Site A		T.H. Wharton Unit 52			Blueray Furnace
	Baseline	BOOS 2	BOOS 1	Baseline	FGR	BOOS/FGR	Baseline	Low NO_x	Baseline	Water	Injection	Cyclic
Chrysene/Benz (a)anthracene	--	--	0.1	--	--	0.1	--	--	--		--	--
Fluoranthene	0.1	0.1	0.2	--	0.1	0.1	--	--	--		0.5	0.03
Fluorene	--	--	0.3	--	--	0.1	--	--	--		--	--
Naphthalene	--	0.9	0.3	--	--	--	--	--	--		1.0	--
Phenanthrene/ Anthracene	0.6	1.0	0.9	0.1	0.2	0.7	--	--	0.5		1.0	0.77
Pyrene	0.1	0.3	0.3	--	--	0.2	--	--	--		0.5	0.01

Table 1-7. Bioassay/Discharge Severity Comparison

Test/Sample	Bioassay Result[a]						
	Stream DS	Microbial Mutagenesis	Cytotoxicity		Rodent Acute Toxicity	Freshwater Algae	Freshwater Fish
			RAM	WI-38			
Crist Unit 7							
>3 μm flyash	830[b]	Neg.	ND	--	--	--	--
<3 μm flyash		Neg.	L	--	--	--	--
Bottom ash	170	Neg.	ND	--	ND	ND	ND
ESP hopper ash	115	Neg.	ND	--	ND	ND	ND
Moss Landing Unit 6							
XAD-2 extract	84	Neg.	--	M	--	--	--
Site B							
Bottom ash	82	Neg.	ND	--	ND	ND	ND
ESP hopper ash	117	Neg.	L	--	ND	--	--
Gas Turbine							
XAD-2 extract	13[b]	Neg.	--	L	--	--	--

- For the sources tested, the flue gas stream presents the greatest potential environmental hazard
- NO_x and SO_2 are the potentially most hazardous flue gas pollutants
- Flue gas discharge severity is decreased or, at worst, does not increase with applying the combustion modifications tested. Changes in emissions due to day-to-day fuel composition changes are often of greater magnitude than those attributable to NO_x control.
- The effluent streams from the sources tested are not mutagenic, and, in general, elicit nondetectable toxicity in bioassay testing
- The combustion modifications tested:
  - -- Have no effect, or increase only slightly, emissions of CO and vapor phase hydrocarbon
  - -- Have no effect on particulate mass emissions
  - -- Have no effect, or tend to increase slightly, emitted particle size distribution
  - -- Have no measurable effect on inorganic trace element emissions or on trace element partitioning tendencies
  - -- Have no effect, or decrease slightly SO_3 and particulate sulfate emissions
  - -- Have little effect on total higher molecular weight organic emissions
  - -- Marginally increase POM emissions, however, emission levels remained on the order of the detection levels of the instrument
- Emissions of many organic priority pollutants were below the detection limit for the sources tested

In light of these conclusions, it can be further stated that the NO_x control methods investigated in the NO_x EA program are environmentally sound since the potential adverse impact of the controlled source is either demonstratably decreased, or is unchanged with effects of NO_x control applications. It must be emphasized, however, that the sources were tested only under steady operation during short-duration tests, and that the controls tested were the relatively straightforward, current technology combustion modifications. Conclusions on the effects of advanced combustion modification controls, and on the potential environmental impacts of combustion sources under unsteady or transient operation must await results from subsequent test programs.

Results from the air quality/regulatory analysis were evaluated to identify research and development priorities for combustion modification control of NO_x emissions and other pollutants. High ranking source control priorities include:

- Further control of the major design coal-fired utility and large industrial boilers to the 60 ng/J NO_x level through the continuation and success of ongoing programs
- Further control of large internal combustion (IC) engines, both spark and compression ignition, through the continuation of ongoing programs
- Control techniques for industrial process combustion; particularly glass melting furnaces, cement kilns, and refinery process heaters, through the continuation of ongoing programs

Pollutant priorities were evaluated by comparing effluent stream concentrations to discharge stream compositions desirable to preclude adverse effects to human health. In addition to NO_x and SO_2, potentially hazardous flue gas stream pollutants include vapor phase SO_3 and condensed sulfate, organic acids, and trace elements such as As, Be, Cd, and V. Coal-fired sources are generally more hazardous due to these pollutants. Potentially hazardous ash stream pollutants from coal-fired sources are the trace elements Fe, Mn, Cr, Ni, Be, Ba, Pb, and occasionally As, Se, Tl, and Sn.

REFERENCES FOR SECTION 1

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1-2. Cleland, J. G., and G. L. Kingsbury, "Multimedia Environmental Goals for Environmental Assessment: Volumes I and II," EPA 600/7-77-136 a,b, November 1977.

1-3. Kingsbury, G. L., et al. "Multimedia Environmental Goals for Environmental Assessment: Volumes III and IV," EPA 600/7-79-176 a,b, August 1979.

1-4. Surprenant, N. F., et al. "Emission Assessment of Conventional Stationary Combustion Systems, Volume 1, Gas- and Oil-fired Residential Heating Sources," EPA-600/7-79-209b, May 1979.

SECTION 2

MULTIMEDIA EMISSIONS DATA

During the first year of the NO_x EA, a preliminary environmental assessment concluded that emissions and operating data needed to perform adequate process engineering, and environmental assessment activities were severely lacking in several key areas. Most noteworthy was the virtual absence of data on noncriteria* flue gas emissions and liquid and solid effluents (Reference 2-1). In response to these identified data needs, NO_x EA field test programs were initiated. Source selection was based on a source/control priority listing developed in the preliminary environmental assessment. These test programs were designed to provide information on changes in emissions and operation due to NO_x controls. In the sections that follow, the data available at the start of the NO_x EA are summarized, source priorities for the field test program based on the status of this data base are presented, and the test program procedures and results are discussed.

2.1 DATA REQUIREMENTS

To address the program goal of assessing the technical and environmental soundness of combustion modification NO_x controls applied to stationary combustion sources requires a detailed base of field test data in which the effects of various NO_x control applications on unit operation and on multimedia pollutant emissions are evaluated. Thus, one of the first steps in the NO_x EA was to evaluate the status of the test data available at the beginning of the program, and to set program data acquisition priorities according to the results of this evaluation. Section 2.1.1 summarizes the early program findings on the survey of available data; Section 2.1.2 outlines the field test priorities assembled to fill critical gaps in the data.

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*Other than NO_x, SO_2, CO, particulate.

2.1.1 Survey of Available Data

In the preliminary environmental assessment, a virtual absence of data on the effects of NO_x control implementation on noncriteria flue gas pollutants and liquid and solid effluents was noted. A summary of the data available at the start of the NO_x EA on the effects of NO_x control application on emissions of pollutants other than NO_x is given in Tables 2-1 through 2-5. These tables show that earlier test efforts were aimed primarily at collecting criteria pollutant emission data, i.e., NO_x, CO, hydrocarbons, and particulate concentrations. There were some sulfur species data and some particulate size data generated. However, data on changes in trace element distribution and organic material emissions resulting from NO_x control implementation were practically nonexistent. In addition, virtually all data taken were under conditions of steady unit operation. Emissions under transient or upset conditions were nonexistent.

2.1.2 Test Priorities

The preliminary environmental assessment performed in the first year of the NO_x EA (Reference 2-1) focused on setting priorities on the order and level of effort to be devoted to the process engineering studies and field testing activities in the remainder of the program. Priority setting was done in three steps. First, source priorities were set for the major combustion source/fuel combinations. Second, control priorities were set for each source/fuel combination. Finally, pollutant priorities deserving evaluation were set.

The source prioritization used the following sequence:

- Subdivide major source categories (e.g., utility boilers) into source/fuel categories (e.g., coal-fired utility); further subdivide to major design types (e.g., tangential) likely to be extensively controlled for NO_x, and minor design types (e.g., cyclones) not likely to be extensively controlled due to dwindling use and/or lack of control flexibility.
- Assess the extent to which controls are used or are planned for each source/fuel category
- Rank source/fuel categories on the basis of nationwide mass emissions of NO_x (documented in Refernce 2-17)

Table 2-1. Survey of Utility Boiler Field Test Data At Test Program Initiation

Data Source	NO_x Controls Tested	Emissions Measured										
							Particulate		Trace Elements		Organics	
		NO_x	CO	HC	SO_2	SO_3	Loading or Opacity	Size	Flue Gas	Ash Streams	Flue Gas	Ash Streams
Coal Fired Utility Boiler												
Exxon (References 2-2, 2-3)	Low excess air	X	X	X			X					
TVA (Reference 2-4)	Staged combustion	X	X	X			X	X				
	Load reduction	X	X	X			X					
KVB (Reference 2-5)	Flue gas Recirculation	X					X				X	
Oil/Gas Fired Utility Boiler												
Exxon (References 2-2, 2-3)	Low excess air	X	X	X								
	Staged combustion	X	X	X								
	Load reduction	X	X	X								
	Flue gas recirculation	X	X	X								

Table 2-2. Survey of Industrial Boiler Field Test Data At Test Program Initiation

Data Source	NO_x Controls Tested	Emissions Measured										
							Particulate		Trace Elements		Organics	
		NO_x	CO	HC	SO_2	SO_3	Loading or Opacity	Size	Flue Gas	Ash Streams	Flue Gas	Ash Streams
Coal Fired Industrial Boilers												
KVB (References 2-6, 2-7)	Low excess air	X	X	X			X					
	Staged combustion	X	X				X					
	Load reduction	X	X				X					
Oil/Gas Fired Industrial Boilers												
KVB (References 2-6, 2-7)	Low excess air	X	X	X			X	X				
Ultrasystems (Reference 2-8)	Staged combustion	X	X	X			X					
	Load reduction	X	X	X			X	X				
	Flue gas recirculation	X	X	X			X					

Table 2-3. Survey of Gas Turbine Test Data At Test Program Initiation

Data Source	NO_x Controls Tested	Emissions Measured										
							Particulate		Trace Elements		Organics	
		NO_x	CO	HC	SO_2	SO_3	Loading or Opacity	Size	Flue Gas	Ash Streams	Flue Gas	Ash Streams
EPA (Reference 2-9)	Load reduction	X	X	X			X					
	Lean primary zone	X	X	X								
	Air blast	X	X	X								
	Water injection	X	X	X			X					

Table 2-4. Survey of IC Engine Test Data at Test Program Initiation

Data Source	NO_x Controls Tested	Emissions Measured										
							Particulate		Trace Elements		Organics	
		NO_x	CO	HC	SO_2	SO_3	Loading or Opacity	Size	Flue Gas	Ash Streams	Flue Gas	Ash Streams
EPA (Reference 2-10)	Derate	X	X	X			X					
	Ignition retard	X	X	X			X					
	Air/fuel ratio alteration	X	X	X			X					
	Reduced air temperature	X	X	X			X					
	Water injection	X	X	X			X					

Table 2-5. Survey of Warm Air Furnace Test Data at Test Program Initiation

Data Source	NO_x Controls Tested	Emissions Measured										
							Particulate		Trace Elements		Organics	
		NO_x	CO	HC	SO_2	SO_3	Loading or Smoke Spot No.	Size	Flue Gas	Ash Streams	Flue Gas	Ash Streams
Battelle (Reference 11)	Baseline tests	X	X	X			X					
EPA (Reference 2-12, 2-13)	Low excess air	X	X	X			X					
	Water/oil emulsions	X	X	X			X					
Rockwell (References 2-14, 2-15)	Low emission burner	X	X	X			X					
Acurex (Reference 2-16)	Low excess air	X	X	X			X					

- Assess the relative baseline environment impact for each source/fuel category using an ambient source analysis model (SAM) (Reference 2-17)
- Identify the relative effectiveness of implementing near-term and far-term source controls in maintaining air quality in urban areas

Once derived, the source priorities were extended to include consideration of specific source/control combinations. Priority setting for current technology considered the extent of control application to specific source and estimates of the cost-effectiveness of a given control. The source/control priorities defined are shown in Table 2-6.

From the list of source/control priorities a candidate list of 19 needed field tests was compiled. From this list, seven source/control test opportunities were selected, influenced by site availability and test collaboration possibilities with other organizations. These seven source/control combination tests are described in Section 2.2.

The pollutants needing evaluation were identified from consideration of potential for adverse environmental impacts, as predicted from the SAM predictions (Reference 2-17) used to guide source priority setting. The pollutants other than NO_x needing assessment were:

- Carbon monoxide
- Vapor phase hydrocarbon
- Particulate load and size distribution
- Sulfur species: SO_2, SO_3, particulate sulfate
- Vapor and condensed phase trace elements
- Vapor and condensed phase organic species, notably polycyclic organic matter (POM)

Thus, as discussed in Section 2.2, an extended IERL Level 1 sampling and analysis protocol was adopted in the test program initiated to allow evaluation of the effects of NO_x control application on emissions of these species.

Table 2-6. Summary of Source/Control Priorities

Source Ranking	Source	Major Emphasis Source Types	Major Emphasis Controls[a]
1	Coal-fired utility boilers, existing	Tangential, opposed and single wall,	LEA, BBF, BOOS, OFA, low-NO_x burners
	Coal-fired utility boilers, new	Same as above	LEA and OFA; low-NO_x burners, enlarged firebox
3, 8	Oil-fired and gas-fired utility boilers	Same as above	LEA, BBF, BOOS, OFA, FGR
2	Coal-fired water-tube, industrial-pulverized	Single or multi-burner wall-fired	LEA, BBF, BOOS, OFA, low-NO_x burners
	Coal-fired water-tube industrial-stoker	Spreader	LEA, OFA
6, 11	Oil-fired and gas-fired watertubes	Single or multi-burner wall-fired	LEA, OFA, low-NO_x burners
14	Coal-fired fire-tube stoker		
5, 12	Oil-fired, gas-fired firetube	Scotch	LEA, FGR, OFA, low-NO_x burners
4	Gas- and oil-fired gas turbines	Utility, industrial simple cycle	Water injection
7	Gas- and oil-fired warm air furnaces	Residential, commercial furnaces	Low-NO_x burners
9	Spark ignition IC engines	Turbocharged, naturally aspirated	Operational tuning, reduced inlet air temperature

[a] LEA -- Low excess air; BBF -- Biased burner firing; BOOS -- Burners out of service; OFA -- Overfire air; FGR -- Flue gas recirculation; RAP -- Reduced air preheat.

Table 2-6. Concluded

Source Ranking	Source	Major Emphasis Source Types	Major Emphasis Controls[a]
10	Compression ignition IC engines (diesel, mixed fuel)	Turbocharged	Operational tuning
11	Industrial process combustion	Process heaters, furnaces, kilns	LEA, load reduction, RAP, FGR, H_2O injection

[a] LEA -- Low excess air; BBF -- Biased burner firing; BOOS -- burners out of service; OFA -- Overfire air; FGR -- Flue gas recirculation; RAP -- Reduced air preheat.

2.2 FIELD TEST PROGRAM

The NO_x EA field test program was designed to fill the data needs identified in Section 2.1.1 according to the priorities outlined in Section 2.1.2. Individual tests were designed to provide information on changes in emissions and operation due to NO_x control implementation. Whenever possible, these tests were conducted as extensions to ongoing test programs. This approach served dual purposes; first enlarging the data base on the source being evaluated, and second, reducing the overall cost of the test program. The sources tested and the general test procedures employed are discussed in the following.

2.2.1 Test Descriptions

The NO_x EA field test program consisted of tests of seven different sources. The sources tested included two coal-fired utility boilers, an oil-fired utility boiler, two coal-fired spreader stoker industrial boilers, an oil-fired gas turbine, and an oil-fired residential heating unit. An overview of the test program is given in Table 2-7. Brief descriptions of the sites tested are given in the following paragraphs. Fuel characteristics are summarized in Appendix F.

Table 2-7. NO$_x$ EA Field Test Program

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Coal-fired Utility Boiler	Kingston #6; 180 MW tangential; twin furnace, 12 burners/furnace, 3 elevations; cyclone, 2 ESP's for particulate control	Baseline Biased Firing (2) BOOS (2)	Continuous NOx, SO$_2$, CO, CO$_2$, O$_2$ Inlet to 1st ESP: -- SASS -- Method 5 -- Method 8 -- Gas grab (C$_1$-C$_6$ HC) Outlet of 1st ESP -- SASS -- Method 5 -- Method 8 -- Gas Grab (C$_1$-C$_6$ HC) Bottom ash Hopper ash (1st ESP, cyclone) Fuel Operating data	TVA
Coal-fired Utility Boiler	Crist #7; 500 MW opposed wall-fired; 24 burners, 3 elevations; ESP for particulate control	Baseline BOOS (2)	Continuous NO$_x$, CO CO$_2$, O$_2$ ESP inlet -- SASS -- Method 5 -- Method 8 -- Gas grab (C$_1$-C$_6$ HC) ESP Outlet -- SASS -- Method 5 -- Method 8 -- Gas Grab (C$_1$-C$_6$ HC) Bottom ash ESP hopper ash Fuel Operating data Bioassay	Exxon

Key to acronyms:

BOOS: Staged combustion technique with burners out of service
ESP: Electrostatic precipitator
FGR: Flue gas recirculation through burner windbox
LEA: Low excess air firing
OFA: Staged combustion with overfire air injection
SASS: Source assessment sampling system for organic and inorganic emission collection and measurement

Table 2-7. Continued

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Oil-fired Utility Boiler	Moss Landing #6; 740 MW opposed wall-fired; 48 burners, 6 elevations	Baseline FGR FGR + OFA	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 -- Gas grab (C_1-C_6 HC) Fuel Operating data Bioassay	None
Coal-fired Industrial Boiler	Traveling grate spreader stoker, 38 kg/s (300,000 lb steam/hr)	Baseline LEA + high OFA	Continuous NO_x, CO CO_2, O_2 Boiler exit: -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) ESP outlet -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) Bottom ash Cyclone hopper ash Fuel Operating data	KVB

Key to acronyms:

BOOS:	Staged combustion technique with burners out of service
ESP:	Electrostatic precipitator
FGR:	Flue gas recirculation through burner windbox
LEA:	Low excess air firing
OFA:	Staged combustion with overfire air injection
SASS:	Source assessment sampling system for organic and inorganic emission collection and measurement

Table 2-7. Concluded

Source Category	Description	Test Points (Unit Operation)	Sampling Protocol	Test Collaborator
Coal-fired Industrial Boiler	Traveling grate spreader stoker, 25 kg/s (200,000 lb steam/hr) ESP for particulate control	Baseline LEA	Continuous NO_x, CO CO_2, O_2 Boiler exit: -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) ESP Outlet -- SASS -- Method 5 -- Shell-Emeryville -- Gas grab (C_1-C_6 HC) Bottom ash ESP hopper ash Fuel Operating data Bioassay	KVB
Oil-fired Gas turbine	T. H. Wharton Station. 60 MW GE MS 7001 C machine	Baseline maximum water injection	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 Fuel Water Operating data Bioassay	General Electric
Oil-fired Residential Heating Unit	Blueray low NO_x furnace, Medford, New York	Continuous cycling	Continuous NO_x, CO CO_2, O_2 -- SASS -- Method 5 -- Method 8 Fuel	EPA/IERL-RTP

Key to acronyms:

BOOS:	Staged combustion technique with burners out of service
ESP:	Electrostatic precipitator
FGR:	Flue gas recirculation through burner windbox
LEA:	Low excess air firing
OFA:	Staged combustion with overfire air injection
SASS:	Source assessment sampling system for organic and inorganic emission collection and measurement

2.2.1.1 Coal-Fired Utility Boilers

Kingston Unit 6

Kingston Unit 6 is a 180 MW electrical output pulverized coal, tangentially-fired, boiler manufactured by Combustion Engineering. This boiler has a twin furnace, radiant, reheat, controlled circulation design. Each furnace has 12 coal nozzles arranged in three elevations with four nozzles at each elevation. There are six pulverizers with each pulverizer feeding a single elevation of nozzles on one furnace.

Kingston Unit 6 has a rated capacity of 582 Mg steam per hour (1.28 x 10^6 lb steam per hour) with a 4-hour maximum capacity of 641 Mg steam per hour (1.41 x 10^6 lb steam per hour). These ratings correspond to 180 and 200 MW generator output, respectively.

Flue gas cleaning equipment consists of a mechanical collector, a low efficiency electrostatic precipitator (ESP), and a high efficiency ESP. Each furnace has its individual particulate removal equipment. Originally, each unit exhausted into its own 91 m (300 ft) stack. With the addition of the high efficiency ESP, two 274 m (900 ft) stacks were erected to serve the entire Kingston Steam Plant.

The testing was conducted on one furnace of the twin furnace design. The arrangement of the fuel, air, ash and flue gas handling systems made it possible to control the operation and collect effluent samples from one furnace with no interference from the second furnace.

The NO_x EA field test program at Kingston consisted of a baseline (normal operation) test and tests under two modes of low NO_x operation. The modes of low NO_x operation were burners out of service (BOOS) and biased burner firing (Bias). Burners out of service is a control technique whereby staged combustion is achieved by curtailing fuel flow to some fuel nozzles and operating them on air only. The remaining nozzles are operated with a higher fuel to air ratio than normal. Biased burner firing is a technique where all burners remain active, but where some are operated with a higher fuel air ratio, and some with a lower, leaner, ratio. Replicate tests were performed under BOOS and Bias conditions.

Crist Unit 7

Crist Unit 7 is a 500 MW pulverized coal-fired boiler built by Foster Wheeler Energy Corporation. It is a horizontally-opposed, natural circulation, radiant, reheat type steam generator. The furnace has 24 burners with 12 burners each on the front and rear walls. The burners are arranged in three rows of four burners on these walls. There are six pulverizers, with each feeding one row of four burners. This unit was originally designed with a pressurized furnace and was recently converted to balanced draft operation.

Crist Unit 7 has a rated capacity of 1.64 Gg steam per hour (3.6 x 10^6 lb/hr) of superheated steam at 17.2 MPa (2500 psia) and 810K (1000^oF) which drives a 500 MW turbine generator. Steam temperature is controlled by spray attemperation and flue gas proportioning dampers.

Flue gas cleaning equipment on Unit 7 consists of a cold side electrostatic precipitator (ESP). The flue gas leaves the boiler in two ducts. There is a separate ESP for each duct. After leaving the ESP's, the ducts are combined and lead to the stack.

This unit was selected because it was the host site for long-term corrosion tests conducted by Exxon Research and Engineering under another EPA/IERL program. Thus, the NO_x EA tests augmented the Exxon test progam to the mutual benefit of both programs. The unit was made available for testing in the NO_x EA Field Testing Program through the cooperation of Gulf Power Company and Exxon Research and Engineering.

The NO_x EA and Exxon field test program at Crist consisted of a baseline (normal operation) test and tests under two modes of low NO_x operation. Both low NO_x modes consisted of staged combustion by burners out of service (BOOS). The first mode (BOOS 1) consisted of turning off coal feed to the top row of burners on the front wall only. The second mode (BOOS 2) consisted of turning off coal feed to the top row of burners on the rear wall only. This resulted in a test program of two low NO_x tests and one baseline test.

2.2.1.2 Oil-Fired Utility Boiler

Moss Landing Unit 6

Moss Landing Unit 6 is a 740 MW horizontally opposed oil- and gas-fired once-through, radiant, reheat, pressurized furnace type steam generator, supplied by the Babcock and Wilcox Company. Capacity of the boiler is 2.3 Gg steam per hour (5.1 x 10^6 lb steam per hour) at 26.5 MPa (3845 psia) and 815K (1005^oF) with a single reheat to 815K

(1005°F). Steam temperature is controlled by superheat-reheat flue gas proportioning dampers, flue gas recirculation, and spray attemperation. Fuel is supplied to the furnace through 48 burners. Burner arrangement is six rows of four burners each on the front and rear furnace walls. The flue gas flows through two ducts to a stack 152 m (500 ft.) tall.

This unit is presently under local NO_x control regulations using both flue gas recirculation through the burners and burners out of service, as retrofit controls, to achieve compliance. Low NO_x emission operation began in 1971. Compliance levels for this boiler are 225 ppm NO_x at 3 percent O_2 while burning oil fuel. During the test program, it was necessary to "remove" the NO_x controls, under a variance granted by the Monterey Bay Unified Air Pollution Control District, for the baseline and flue gas recirculation tests.

Moss Landing Unit 6 was selected because it is one of the most stringently controlled (for NO_x) oil-fired boilers in the nation. NO_x control implementation on this unit is well documented. It was made available for testing through the cooperation of the Pacific Gas and Electric Company.

The NO_x EA field test program at Moss Landing consisted of a baseline test and tests under two modes of low NO_x operation using oil fuel. The first mode of low NO_x operation was combined burners out of service (BOOS) and flue gas recirculation (FGR) to the windbox. The second mode was flue gas recirculation through the burners only.

2.2.1.3 Coal-Fired Spreader Stoker Industrial Boilers

Site A

The first unit tested in this study was a 100 MW thermal input Foster Wheeler Ltd. boiler combined with a Detroit Stoker traveling grate spreader stoker. This test program was performed in conjunction with KVB, Inc., in their "Field Testing of Industrial Stoker Coal-fired Boilers for Emissions Control and Efficiency Improvement" program, Reference 2-26. The total effective grate area is about 48 m^2 (515 ft^2). Coal is supplied through seven feeders located in the front wall of the furnace. The recommended coal sizing is 1.9 cm (0.75 in) with no more than 25 percent less than 0.63 cm (0.25 in). Overfire air (OFA) is injected into the furnace through two rows of ports located both on the back and front walls of the furnace. The overfire air is delivered using a fan that is independent of the forced draft system used for supplying undergrate air. Therefore, the flowrates of undergrate air and overfire air can be set independently. A tubular air preheater is used to heat the undergrate air to about 450K (350°F). The overfire air is not preheated. The Foster Wheeler steam generator was designed to produce 38 kg/s (300,000 lb/hr) of saturated steam at a pressure of 2.3 MPa (320 psig).

The gases and particulate leaving the boiler pass through the boiler-bank collector, air heater, mechanical ash collector, ESP, economizer, and wet SO_2 scrubber before entering the stack. The design efficiency of the mechanical collector is 70 percent. The design efficiency of the ESP is 97.83 percent with one of the ESPs force fields out of service.

To improve system efficiency some of the flyash can be reinjected into the furnace. Particulate material collected in the boiler-bank collector, air heater collector, and mechanical collector may be continuously reinjected. Reinjection rates are controlled by the boiler operator. The flyash reinjection ports are located on the rear wall of the furnace under the OFA ports. The reinjection air is supplied from the OFA fan.

During this program, two furnace operating conditions were examined. In the first test the unit was run under normal operating conditions. A second test was performed with increased overfire air (at constant overall excess air) to determine the effect on NO_x as well as on particulate and trace element emissions.

Site B

The unit tested in this program was a single pass 70 MW thermal input Riley boiler equipped with a Riley spreader stoker. The unit has a continuous rating of 25 kg/s steam (200,000 lb/hr) with a 2 hour maximum capacity of 28 kg/s. The steam is produced at a pressure of 1.38 MPa (185 psig) and temperature of 533K (500°F). The boiler is also equipped with a flyash reinjection system. All the ash from the boiler hopper is reinjected and part of the ash from the the mechanical collector is also reinjected. An ESP is used for final flyash control. The boiler is also equipped with an economizer.

The NO_x EA field test program at this site consisted of a baseline (normal operation) test and a test under the low excess air operating mode. As in the Site A test program, Site B tests were conducted in conjunction with KVB in their stoker emissions control and efficiency improvement program, Reference 2-27.

2.2.1.4 Oil-Fired Gas Turbine

T. H. Wharton Unit 52

The field tests were conducted on Unit 52 of the T. H. Wharton Generating Station of the Houston Lighting and Power Company in Houston, Texas. Unit 52 is General Electric Model MS 7001C simple-cycle, single-shaft, heavy-duty stationary gas turbine rated at 70.8 MW nominal electrical output. The unit is equipped with a water injection system to control NO_x. The degree of NO_x control can be adjusted by altering the quantity of water injected -- the more water injected, the greater the degree of control. The first test on Unit 52, a baseline test, was run with no water injected. The second test was run with a water injection to fuel mass ratio of approximately 0.42, a ratio sufficient to bring NO_x emissions to within 75 ppm at 15 percent O_2, which is the level of the proposed New Source Performance Standards (NSPS). Unit 52 was selected because its design is typical of large scale simple cycle utility gas turbines equipped with water injection and because of the possibility of collaborating with the engine manufacturer in detailed process evaluation tests. Through the cooperation of the Houston Lighting and Power Company and the General Electric Company, this unit was made available for testing in the NO_x EA program.

2.2.1.5 Oil-Fired Residential Heating Unit

Blueray Systems

The unit tested was a distillate oil-fired residential heating unit manufactured by Blueray Systems, Inc. This unit was installed in a Medford, Long Island, New York residence and had been in service for about one year.

The Blueray furnace is a low emission design that utilizes combustion gas recirculation to vaporize the oil and provide thorough mixing of the oil and air. The result is a low emission burner that is characterized by its diffuse blue flame that fills the combustion chamber.

The model tested was Blueray's BF-60. This unit fires distillate fuel oil at 0.63 mℓ/s (0.6 gal/hr). The rated heat input is 24.6 kJ/s (84,000 Btu/hr). Tests under continuous and cyclical operation were conducted.

2.2.2 Test Procedures

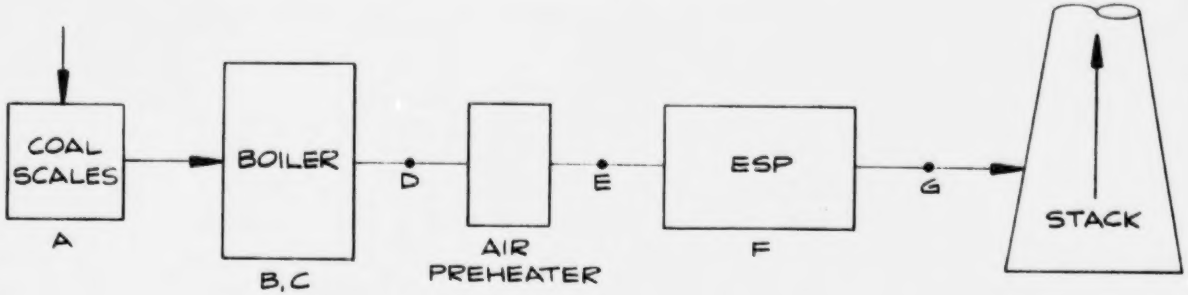
The NO_x EA field tests were conducted to identify any changes in emissions and operation due to NO_x control implementation. Thus, tests were conducted under both controlled and uncontrolled (for NO_x) conditions. Other operating conditions were held constant so that changes in source operation due to NO_x control could be evaluated.

The test plan developed for each test called for sampling all influent and effluent streams with the exception of the ambient air. Continuous monitors were employed to measure flue gas NO_x, CO, CO_2, and O_2. EPA Level 1 procedures (References 2-18 and 2-19) were used to sample the flue gas and all discharge ash streams for trace element and organic species. The purpose of such Level 1 tests is to obtain preliminary environmental assessment information, identify problem areas, and provide the basis for setting priorities for steam components and classes of materials for further consideration in overall assessment. As such, the results of the sampling and analysis procedures are quantitative to within a factor of 2 to 3. Flue gas sampling upstream and downstream of particulate collection devices were always performed. Flue gas particulate and sulfur species concentrations were measured in each test. An example of the samples collected during a test are shown in Figure 2-1. Operating data sufficient to calculate unit efficiency, cycle efficiency, and verify consistent operation, were also recorded.

2.3 CHEMICAL ANALYSES

Laboratory chemical analyses of samples collected generally followed IERL-RTP defined Level 1 procedures (References 2-18 and 2-19) with a few exceptions and additions. The analysis scheme adopted for SASS train samples is illustrated in Figure 2-2. The analysis scheme for solid (ash) samples is shown in Figure 2-3. The general organic analysis scheme is shown in Figure 2-4.

A specific exception to the Level 1 protocol dealt with sample trace element analysis. Here, instead of assaying for trace elements by


COAL SCALES
A
BOILER
B,C
D
AIR PREHEATER
E
ESP
F
G
STACK

Sampling Location	Type of Sample
A -- Coal Scales	Grab Sample -- Coal
B -- Sluice Water Inlet	Grab Sample -- Sluice Water Blank
C -- Bottom Ash Outlet	Grab Sample -- Bottom Ash Slurry
D -- Airheater Inlet	Gas Sample -- Continuous Monitors
E -- ESP Inlet	Gas Sample -- SASS, EPA 5/8
F -- ESP	Grab Sample -- ESP Ash
G -- ESP Outlet	Gas Sample -- SASS, EPA 5/8, Gas Grab Sample for GC analysis

Figure 2-1. Sampling Locations

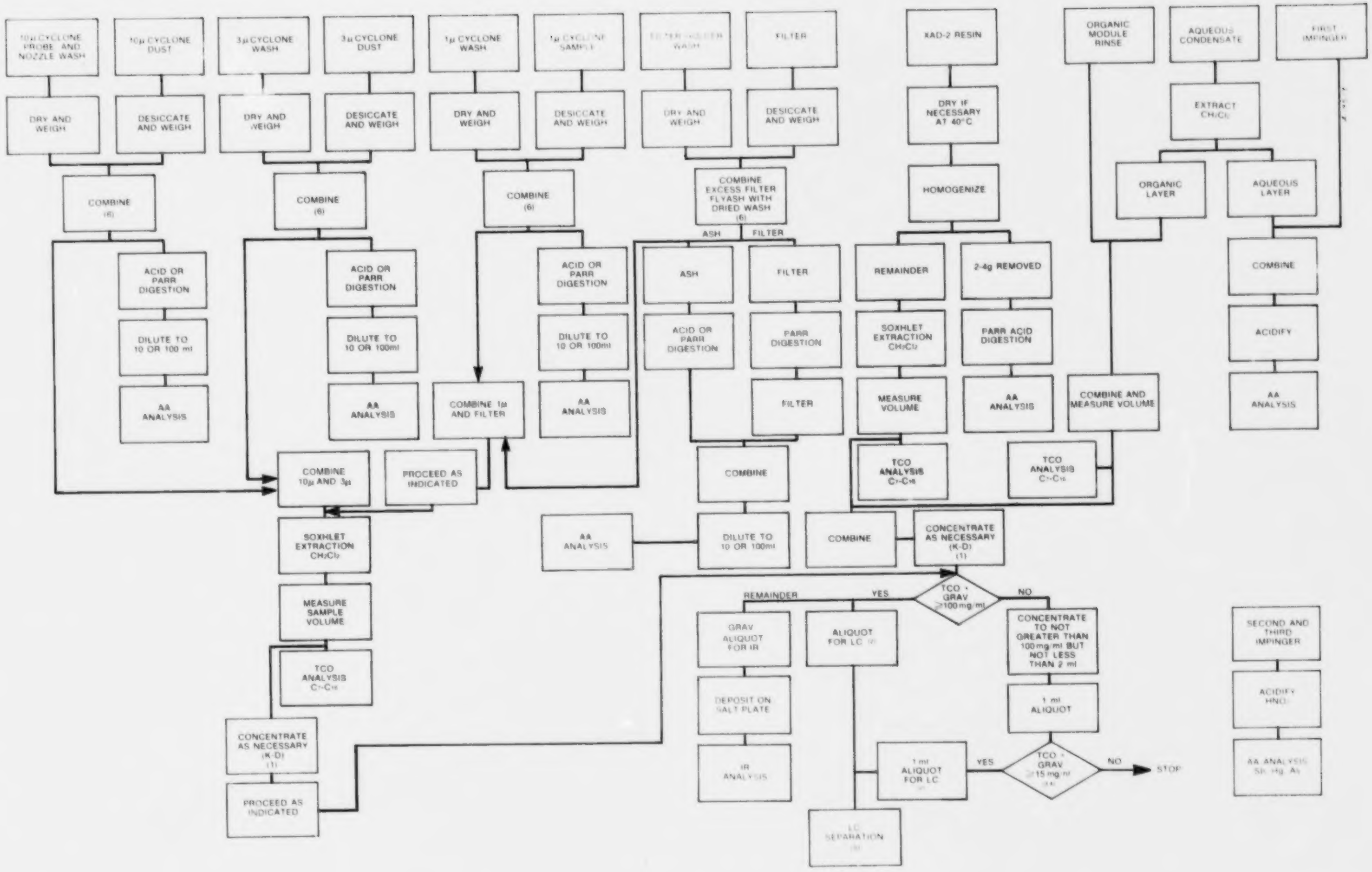

10µ CYCLONE PROBE AND NOZZLE WASH
10µ CYCLONE DUST
3µ CYCLONE WASH
3µ CYCLONE DUST
1µ CYCLONE WASH
1µ CYCLONE SAMPLE
FILTER HOLDER WASH
FILTER
XAD-2 RESIN
ORGANIC MODULE RINSE
AQUEOUS CONDENSATE
FIRST IMPINGER
DRY AND WEIGH
DESICCATE AND WEIGH
DRY AND WEIGH
DESICCATE AND WEIGH
DRY AND WEIGH
DESICCATE AND WEIGH
DRY AND WEIGH
DESICCATE AND WEIGH
DRY IF NECESSARY AT 40°C
EXTRACT CH2Cl2
COMBINE (6)
COMBINE (6)
COMBINE (6)
COMBINE EXCESS FILTER FLYASH WITH DRIED WASH (6)
HOMOGENIZE
ORGANIC LAYER
AQUEOUS LAYER
ASH
FILTER
ACID OR PARR DIGESTION
DILUTE TO 10 OR 100 ml
AA ANALYSIS
ACID OR PARR DIGESTION
DILUTE TO 10 OR 100ml
AA ANALYSIS
ACID OR PARR DIGESTION
DILUTE TO 10 OR 100ml
AA ANALYSIS
ASH
ACID OR PARR DIGESTION
FILTER
PARR DIGESTION
FILTER
REMAINDER
SOXHLET EXTRACTION CH2Cl2
MEASURE VOLUME
TCO ANALYSIS C7-C16
2-4g REMOVED
PARR ACID DIGESTION
AA ANALYSIS
COMBINE AND MEASURE VOLUME
TCO ANALYSIS C7-C16
COMBINE
ACIDIFY
AA ANALYSIS
COMBINE 1µ AND FILTER
COMBINE 10µ AND 3µ
PROCEED AS INDICATED
SOXHLET EXTRACTION CH2Cl2
MEASURE SAMPLE VOLUME
TCO ANALYSIS C7-C16
CONCENTRATE AS NECESSARY (K-D) (1)
PROCEED AS INDICATED
COMBINE
DILUTE TO 10 OR 100ml
AA ANALYSIS
COMBINE
CONCENTRATE AS NECESSARY (K-D) (1)
TCO + GRAV ≥100 mg/ml
YES
NO
REMAINDER
GRAV ALIQUOT FOR IR
DEPOSIT ON SALT PLATE
IR ANALYSIS
ALIQUOT FOR LC
LC SEPARATION
CONCENTRATE TO NOT GREATER THAN 100 mg/ml BUT NOT LESS THAN 2 ml
1 ml ALIQUOT
TCO + GRAV ≥15 mg/ml
YES
NO
STOP
1 ml ALIQUOT FOR LC
SECOND AND THIRD IMPINGER
ACIDIFY HNO3
AA ANALYSIS Sb, Hg, As

Figure 2-2. Analysis Scheme for SASS Train Samples

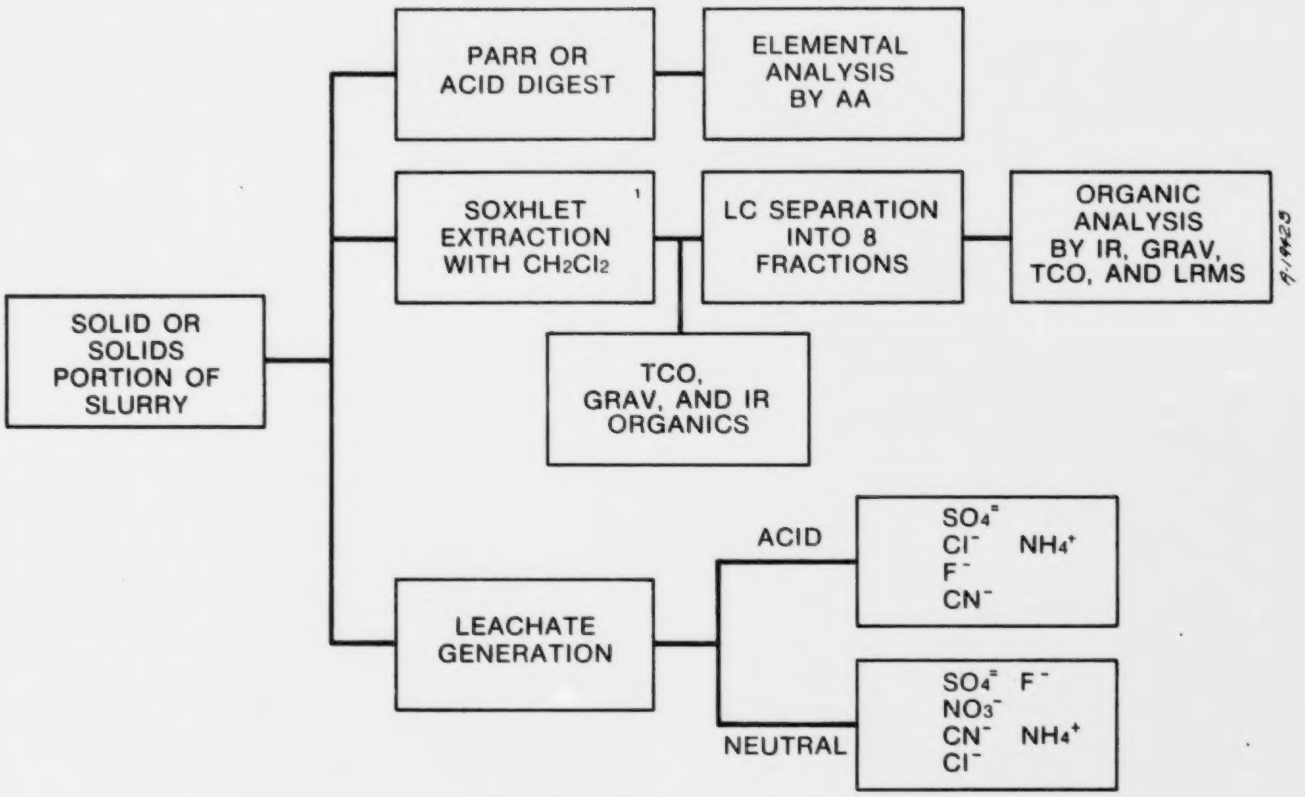

SOLID OR SOLIDS PORTION OF SLURRY
PARR OR ACID DIGEST
ELEMENTAL ANALYSIS BY AA
SOXHLET EXTRACTION WITH CH_2Cl_2
LC SEPARATION INTO 8 FRACTIONS
ORGANIC ANALYSIS BY IR, GRAV, TCO, AND LRMS
A-19423
TCO, GRAV, AND IR ORGANICS
LEACHATE GENERATION
ACID
$SO_4^=$ Cl^- NH_4^+ F^- CN^-
NEUTRAL
$SO_4^=$ F^- NO_3^- CN^- NH_4^+ Cl^-

Figure 2-3. Analysis Scheme for Solid Samples

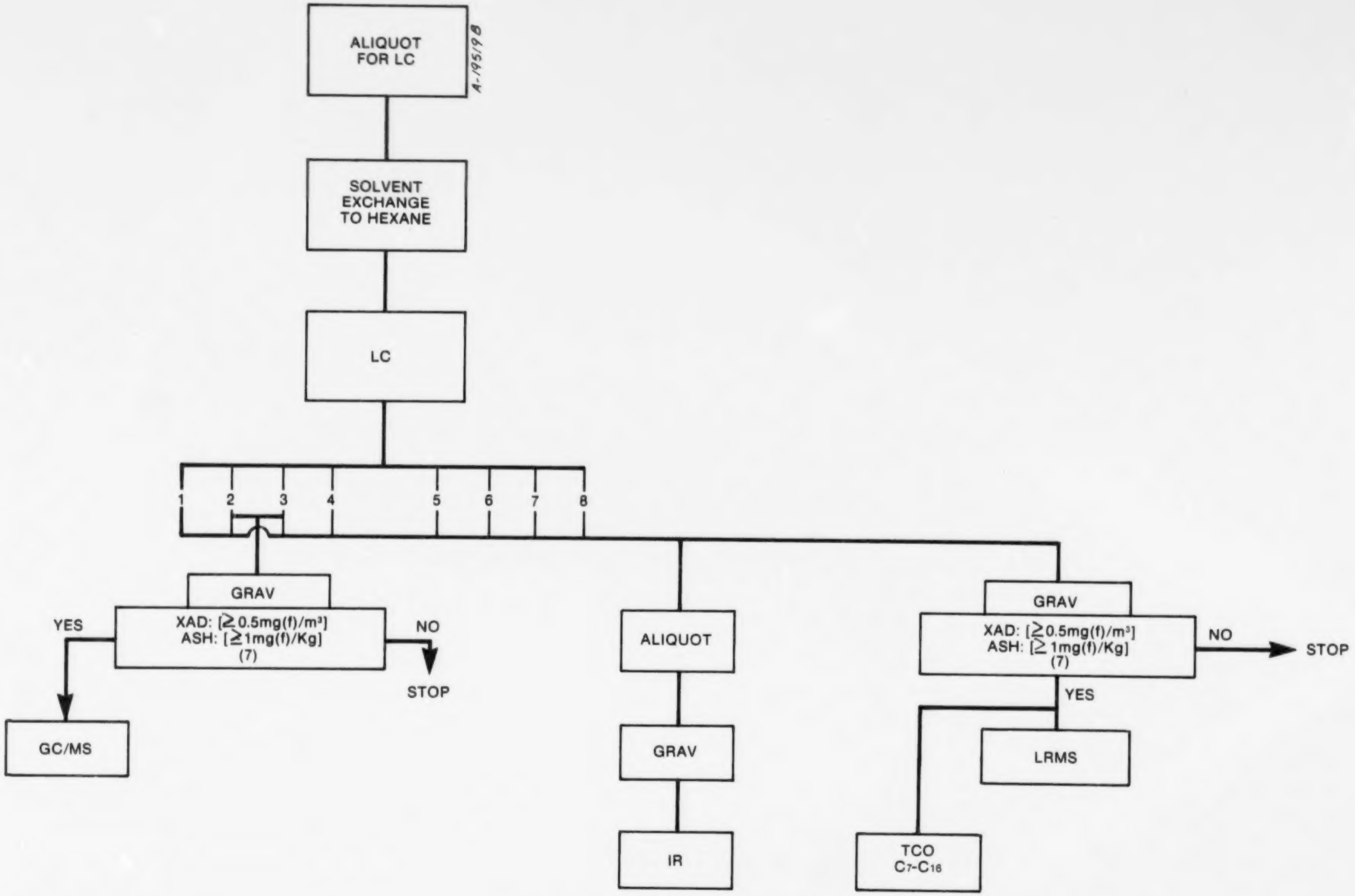

A-19519B
ALIQUOT FOR LC
SOLVENT EXCHANGE TO HEXANE
LC
1
2
3
4
5
6
7
8
GRAV
XAD: [≥0.5mg(f)/m³]
ASH: [≥1mg(f)/Kg]
(7)
YES
NO
STOP
GC/MS
ALIQUOT
GRAV
IR
GRAV
XAD: [≥0.5mg(f)/m³]
ASH: [≥1mg(f)/Kg]
(7)
NO
STOP
YES
LRMS
TCO
C7-C16

Figure 2-4. LC Separation Scheme

spark source mass spectrometry, atomic absorption spectroscopy as shown in Figure 2-5 was employed to determine the 25 more commonly occurring elements listed in Table 2-8. Another exception dealt with organic analyses of flue gas (XAD-2 extract), particulate, and liquid/solid samples.

Here the analyses were extended, when feasible, to the determination of polycyclic organic compounds (POM) and later to the determination of the priority pollutant compounds listed in Table 2-9. Other minor exceptions were:

- The SASS particulate combining scheme shown in Figure 2-6 was employed to maximize the usefulness of analysis results
- Analyses for the ionic species listed in Table 2-10 were performed using specific ion electrodes instead of test kits

Following the procedures of the Level 1 analysis, data listed below can be obtained for each test point:

- Continuous flue gas NO_x, CO, CO_2 and O_2
- Flue gas SO_2, SO_3, and speciated C_1-C_6 hydrocarbon
- Flue gas particulate load and size distribution
- Flue gas vapor phase trace element composition for the 25 elements listed in Table 2-8
- Flue gas C_7 organic composition in terms of seven compound polarity fractions and flue gas composition for the species listed in Table 2-9
- Particulate composition for the 25 elements listed in Table 2-8 and the six ionic species listed in Table 2-10, as a function of particulate size
- Particulate organic composition for severe polarity fractions, and for the species listed in Table 2-9, as a function of particulate size
- Liquid/solid stream (bottom, hopper ash) composition for the 25 elements listed in Table 2-8 and the six ionic species listed in Table 2-10
- Liquid/solid stream (bottom, hopper ash) organic composition for seven polarity fractions and for the species listed in Table 2-9

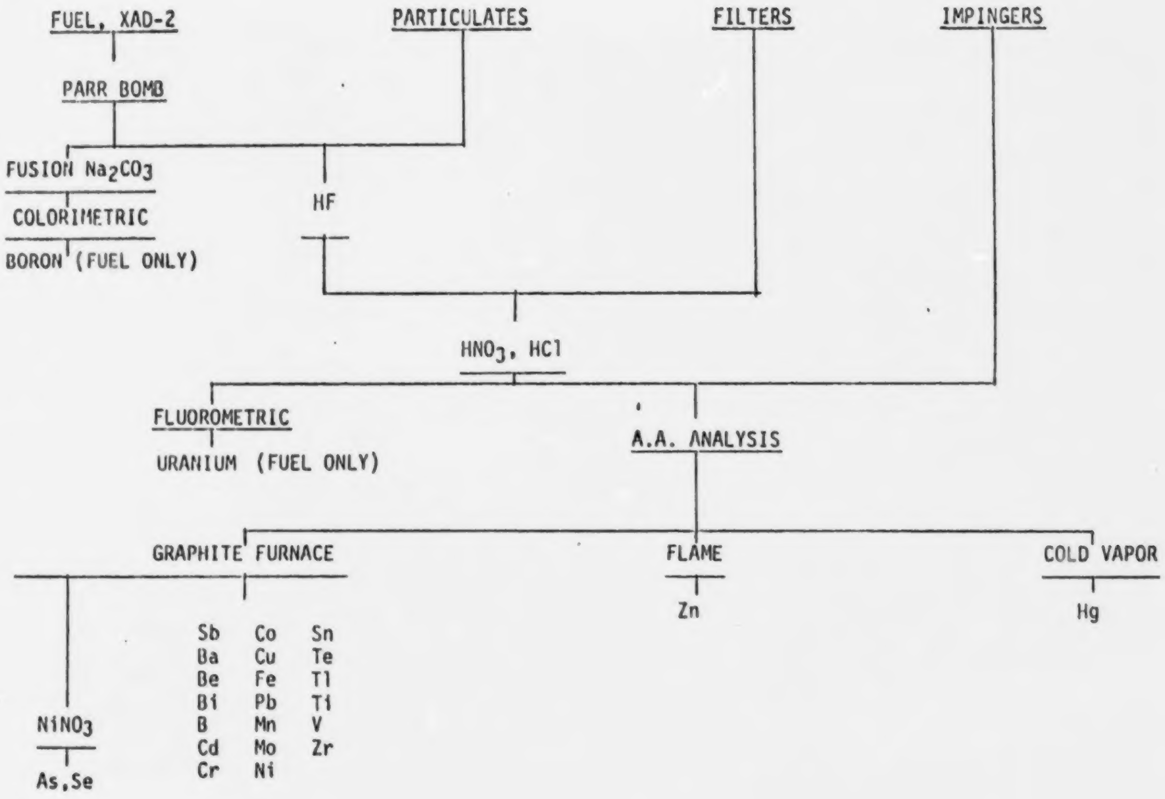

FUEL, XAD-2
PARTICULATES
FILTERS
IMPINGERS
PARR BOMB
FUSION Na_2CO_3
HF
COLORIMETRIC
BORON (FUEL ONLY)
HNO_3, HCl
FLUOROMETRIC
URANIUM (FUEL ONLY)
A.A. ANALYSIS
GRAPHITE FURNACE
FLAME
COLD VAPOR
Zn
Hg
Sb Co Sn
Ba Cu Te
Be Fe Tl
Bi Pb Ti
B Mn V
Cd Mo Zr
Cr Ni
$NiNO_3$
As,Se

Figure 2-5. Elemental Analysis Flowsheet

Table 2-8. Elemental Analysis: Species Determined

- Antimony (Sb)
- Arsenic (As)
- Barium (Ba)
- Beryllium (Be)
- Bismuth (Bi)
- Boron (B)
- Cadmium (Cd)
- Chromium (Cr)
- Cobalt (Co)
- Copper (Cu)
- Iron (Fe)
- Lead (Pb)
- Manganese (Mn)
- Mercury (Hg)
- Molybdenum (Mo)
- Nickel (Ni)
- Selenium (Se)
- Tellurium (Te)
- Thallium (Ti)
- Tin (Sn)
- Titanium (Ti)
- Uranium (U)
- Vanadium (V)
- Zinc (Zn)
- Zirconium (Zr)

Table 2-9. Compounds for Which GC/MS Analysis was Performed

- Acenapthene[a]
- Acenapthalene[a]
- Anthanthrene[a]
- Anthracene[a]
- Benzidine[a]
- Benzo(a)anthracene[a]
- 3,4-Benzofluoranthene[a]
- Benzo(k)fluoranthene[a]
- Benzo(g,h,i)perylene[a]
- Benzo(a)pyrene[a]
- Benzo(e)pyrene[a]
- 4-Bromophenyl phenyl ether[a]
- Butyl benzyl phthalate[a]
- Bis(2-chloroethoxy) methane[a]
- Bis(2-chloroethyl)ether[a]
- Bis(2-chloroisopropyl) ether[a]
- 2-Chloronaphthalene
- 4-Chlorophenyl phenyl ether[a]
- Chrysene[a]
- Dibenzo(a,h)anthracene[a]
- Dibenzo(c,g)carbazole[a]
- Dibenzo(a,h)pyrene[a]
- Dibenzo(a,i)pyrene[a]
- Di-n-butyl phthalate[a]
- 1,2-Dicholorobenzene[a]
- 1,3-Dichlorobenzene[a]
- 1,4-Dichlorobenzene[a]
- Bis (2-ethylhexyl) phthalate[a]
- 3,3'-Dichlorobenzidine[a]
- Diethyl phthalate[a]
- 7,12-Dimethyl benz(a)anthracene[a]
- Dimethyl phthalate[a]
- 2,4-Dinitrotoluene[a]
- 2,6-Dinitrotoluene[a]
- Di-n-octyl phthalate[a]
- 1,2-Diphenylhydrazine[a] (as azobenzene)
- Fluoranthene[a]
- Fluorene[a]
- Hexachlorobenzene[a]
- Hexachlorobutadiene[a]
- Hexachlorocyclopentadiene[a]
- Hexachloroethane[a]
- Indeno(1,2,3-c,d)pyrene[a]
- Isophorone
- 3-Methyl cholanthrene[a]
- Naphthalene[a]
- Nitrobenzene[a]
- N-nitrosodiphenylamine[a]
- N-nitrosodi-n-propylamine[a]
- Perylene[a]
- Phenanthrene[a]
- Pyrene[a]
- 2,3,7,8-Tetrachlorodibenzo-[a] p-dioxin
- 1,2,3-Trichlorobenzene[a]

[a] Compound in calibration standard.

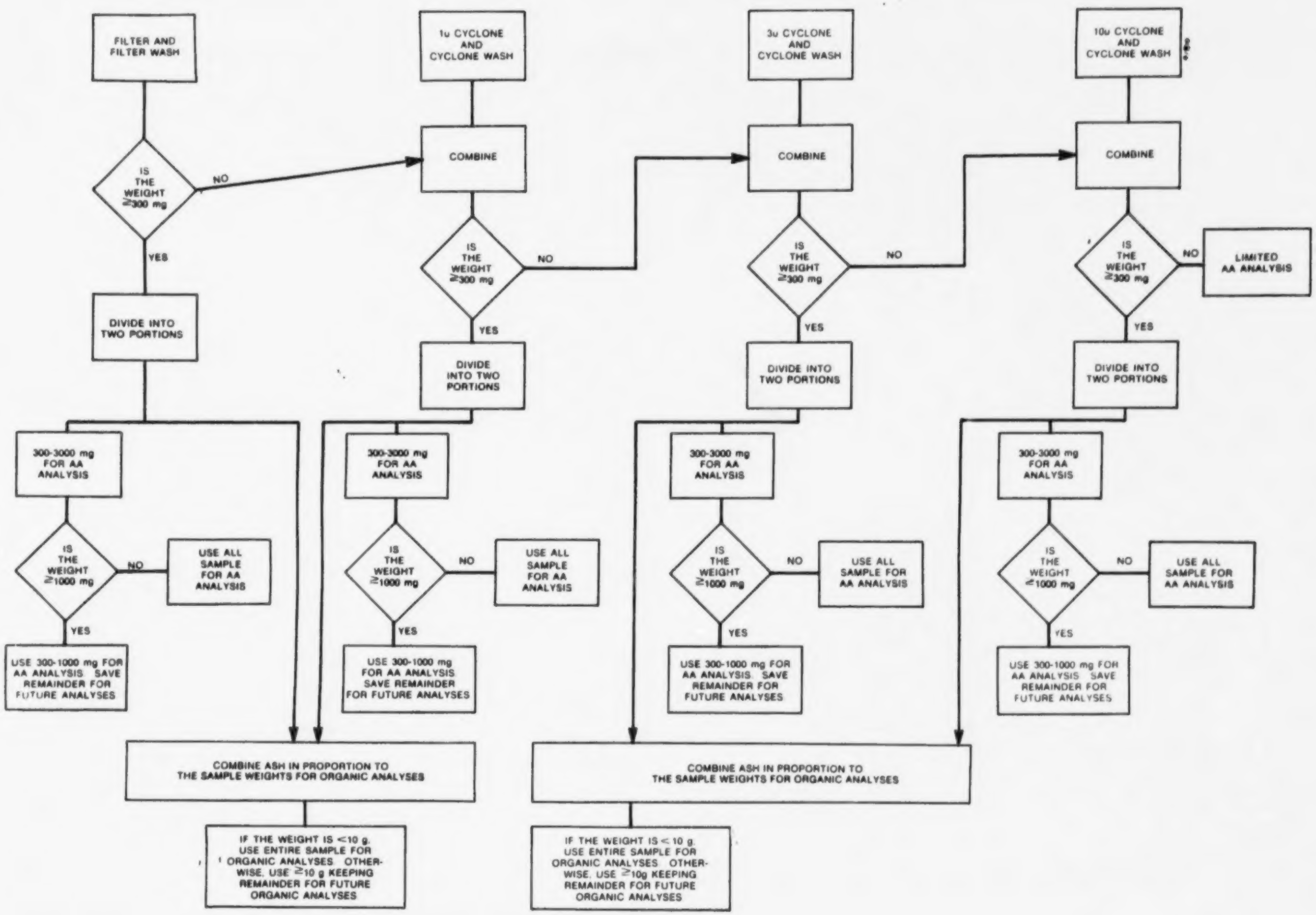

FILTER AND FILTER WASH
IS THE WEIGHT ≥300 mg
NO
YES
DIVIDE INTO TWO PORTIONS
300-3000 mg FOR AA ANALYSIS
IS THE WEIGHT ≥1000 mg
NO
USE ALL SAMPLE FOR AA ANALYSIS
YES
USE 300-1000 mg FOR AA ANALYSIS. SAVE REMAINDER FOR FUTURE ANALYSES
1u CYCLONE AND CYCLONE WASH
COMBINE
IS THE WEIGHT ≥300 mg
NO
YES
DIVIDE INTO TWO PORTIONS
300-3000 mg FOR AA ANALYSIS
IS THE WEIGHT ≥1000 mg
NO
USE ALL SAMPLE FOR AA ANALYSIS
YES
USE 300-1000 mg FOR AA ANALYSIS SAVE REMAINDER FOR FUTURE ANALYSES
COMBINE ASH IN PROPORTION TO THE SAMPLE WEIGHTS FOR ORGANIC ANALYSES
IF THE WEIGHT IS <10 g, USE ENTIRE SAMPLE FOR ORGANIC ANALYSES. OTHERWISE, USE ≥10 g KEEPING REMAINDER FOR FUTURE ORGANIC ANALYSES
3u CYCLONE AND CYCLONE WASH
COMBINE
IS THE WEIGHT ≥300 mg
NO
YES
DIVIDE INTO TWO PORTIONS
300-3000 mg FOR AA ANALYSIS
IS THE WEIGHT ≥1000 mg
NO
USE ALL SAMPLE FOR AA ANALYSIS
YES
USE 300-1000 mg FOR AA ANALYSIS. SAVE REMAINDER FOR FUTURE ANALYSES
10u CYCLONE AND CYCLONE WASH
COMBINE
IS THE WEIGHT ≥300 mg
NO
LIMITED AA ANALYSIS
YES
DIVIDE INTO TWO PORTIONS
300-3000 mg FOR AA ANALYSIS
IS THE WEIGHT ≥1000 mg
NO
USE ALL SAMPLE FOR AA ANALYSIS
YES
USE 300-1000 mg FOR AA ANALYSIS. SAVE REMAINDER FOR FUTURE ANALYSES
COMBINE ASH IN PROPORTION TO THE SAMPLE WEIGHTS FOR ORGANIC ANALYSES
IF THE WEIGHT IS < 10 g, USE ENTIRE SAMPLE FOR ORGANIC ANALYSES. OTHERWISE, USE ≥10g KEEPING REMAINDER FOR FUTURE ORGANIC ANALYSES

Figure 2-6. SASS Particulate Sample Combining Scheme

- Particulate and ash combustible material content
- Fuel proximate and ultimate analysis (heating value, and water, C, H, O, N, and S content)
- Fuel trace element content for the 25 elements listed in Table 2-8

The above data satisfy the specific program needs identified. Specific attention was focused on obtaining data on emitted POM, SO_3 and condensed sulfate, and trace element levels as a function of particulate size, especially as these are affected by NO_x control applications.

Table 2-10. Ionic Analysis: Species Determined

Chloride (Cl^-)
Fluoride (F^-)
Nitrate (NO_3^-)
Cyanide (CN^-)
Sulfate (SO_4^{2-})
Ammonia (NH_4^+)

2.4 BIOASSAY ANALYSES

Bioassay testing in accordance with IERL-RTP guidelines (Reference 2-20) was performed on samples collected during tests of the gas turbine, the Crist Unit 7, the Moss Landing Unit 6 utility boiler and the Site B industrial boiler. The bioassays are conducted on samples collected during the controlled (for NO_x) tests only. The general Level 1 bioassay protocol for the NO_x EA tests is given in Table 2-11. This test protocol includes both health effects and ecological effects tests. However, as shown in Table 2-11, sample size requirements for certain tests are substantial. Thus, performing these tests was often precluded due to insufficient samples. The actual bioassays performed in the test program are listed in Table 2-12.

Table 2-11. Bioassay Analysis Protocol

Sample Type	Bioassay Test Protocol	Sample Size Requirements
SASS cyclones, 10 + 3	Microbial Mutagenesis	1.0g
	Cytotoxicity, RAM	0.5g
SASS cyclones, 1 + filter	Microbial Mutagenesis	1.0g
	Cytotoxicity, RAM	0.5g
XAD-2 extract	Microbial Mutagenesis	50 m
	Cytotoxicity, WI-38	50 m
Bottom ash	Microbial Mutagenesis	1.0g
	Cytotoxicity, RAM	0.5g
	Rodent Acute Toxicity	100g
	Freshwater Algal Bioassay	50 kg
	Freshwater Static Bioassay	(200 ℓ if sluiced)
ESP hopper ash	Microbial Mutagenesis	1.0g
	Cytotoxicity, RAM	0.5g
	Rodent Acute Toxicity	100g
	Freshwater Algal Bioassay	50 kg
	Freshwater Static Bioassy	(200 ℓ if sluiced)

2.5 TEST RESULTS

The preceding sections outlined the source selection criteria for the NO_x EA field test program, described the sources tested, and summarized the sampling, chemical analysis, and bioassay testing procedures followed in the test program. Emissions data obtained are presented in this section, by source category.

2.5.1 Utility Boilers

Three utility boilers were tested in the NO_x EA program:

- A coal-fired tangential unit (Kingston Unit 6) with biased firing and with BOOS for NO_x control
- A coal-fired opposed wall unit (Crist Unit 7) with two BOOS patterns for NO_x control

Table 2-12. Bioassay Tests Performed

Field Test	Bioassay						
	Sample	Microbial Mutagenesis	RAM	WI-38	RAT	Freshwater Algal	Freshwater Fish
Crist Unit 7, BOOS 2	SASS cyclones 10 + 3μm	X	X				
	SASS cyclones 1μm + filter	X	X				
	Bottom ash	X	X		X	X	X
	ESP hopper ash	X	X		X	X	X
Moss Landing Unit 6 BOOS and FGR	XAD-2 extract	X		X			
Site B Stoker Low Excess Air	Bottom ash	X	X		X	X	X
	ESP hopper ash	X	X		X		
Gas Turbine Water Injection	XAD-2 extract	X		X			

- An oil-fired tangential unit (Moss Landing Unit 6) with flue gas recirculation (FGR) and combined FGR and BOOS for NO_x control

A summary of test results by fuel is reported in the following.

2.5.1.1 Coal-Fired Utility Boilers

Kingston Unit 6

As noted in Section 2.2.1, the test program conducted on Kingston Unit 6 encompassed testing under baseline (uncontrolled), biased firing (Bias), and BOOS operating conditions (these concepts are defined in Section 2.2.1.1). Two replicate tests were performed under the controlled (Bias and BOOS) conditions. However, complete sample analyses were done only for one set of samples under each condition. Thus, data are presented below for only one of the Bias and one of the BOOS tests. More detailed test results, discussion, and data are reported in Reference 2-21.

The NO_x controls employed in this test program did not appear to cause any operating problems during the test program. Steam temperatures were maintained at 810K (1000°F) and load and furnace exit temperatures were relatively uniform. No excessive slagging of the furnace was noticed, either through visual observations or through steam attemperation requirements. It must be noted, however, that these tests were each of 5- to 6-hours duration. The long-term effects of continuous operation under low NO_x firing modes were not evaluated in this study.

The main operating problem experienced with low NO_x firing was reduced load in the BOOS mode. By not admitting fuel to one elevation of fuel nozzles, a load limiting condition was reached. During peak load periods, Kingston Unit 6 turbine generator output is 200 MW. During the test program, output was limited to 177 MW, the maximum achievable with one elevation of fuel nozzles admitting air only. This is below the continuous rating of 180 MW for the Kingston unit.

Boiler efficiency computed by the American Society of Mechanical Engineers short form remained unchanged or improved slightly with NO_x controls, as shown in Table 2-13. This was due to lowering the excess air levels without increasing the levels of CO or unburned carbon in the ash.

Table 2-14 shows flue gas vapor species concentration data for the three firing conditions. As noted, NO_x emissions were reduced

Table 2-13. Boiler Efficiency: Kingston Unit 6

	Baseline	Bias	BOOS
Heat input (% Baseline)	100	101	92
Excess O_2 (% Baseline)	100	91	85
Efficiency (%)	86.52	86.59	86.84
Heat loss due to combustibles in flyash (%)	0.70	0.75	0.71
Heat loss due to dry flue gas (%)	6.79	6.70	6.44

Table 2-14. Flue Gas Composition: Kingston Unit 6

	Baseline	Bias	BOOS
NO_x, ng/J as NO^2	299	205	186
ppm[a]	490	336	304
SO_2, ng/J	1500	1250	1570
ppm[a]	1670	1350	1590
SO_3, ng/J	4.3	3.9	4.5
ppm[a]	4.0	3.7	4.2
CO, ng/J	10.6	13.0	8.1
ppm[a]	28.6	35.0	21.7
CO_2, % dry	13.9	14.4	14.6
O_2, % dry	5.18	4.71	4.40

[a] 3 percent O_2, dry.

31 percent under biased firing, and 37 percent under BOOS firing. CO emissions were controlled at levels below 100 ppm throughout the test program. This was done by reducing excess air levels until increases in CO emissions were seen. The excess air level was then increased slightly to provide a comfortable operating margin. Thus CO levels varied little from test to test. Emitted SO_2 levels varied only with fuel sulfur content, which averaged 2.2, 1.8, and 2.1 percent, respectively, for the baseline, bias, and BOOS tests. In addition, the $SO_3/(SO_2 + SO_3)$ ratio was not affected by changes in firing mode.

Particulate load results, both upstream and downstream of the ESP are shown in Table 2-15. The data show that ESP collection efficiency increased slightly in the BOOS test. In addition, particle size distribution measurements indicated that the biased firing condition results in slightly larger particle size than either the BOOS or the baseline conditions.

Table 2-15. Method 5 Particulate Concentration (μg/J): Kingston Unit 6

	Baseline	Bias	BOOS
ESP Inlet	1.407	1.373	1.232
ESP Outlet	0.228	0.238	0.160
ESP Collection Efficiency (%)	83.8	82.7	87.0

Table 2-16 shows Level 1 organic content results from SASS train samples taken downstream of the ESP. Organic analyses of SASS samples were only performed for the baseline and the BOOS test. The data in the table show that condensed (particulate) organic emissions were comparable for the two firing modes. However, vapor phase (XAD-2) organics appear higher under BOOS firing.

Table 2-16. SASS Sample Organic Analysis Results ($\mu g/dscm$): Kingston Unit 6

Sample	Baseline	BOOS
XAD-2 extract	75	790
SASS cyclones 10 μm + 3 μm	47	44
SASS cyclones 1 μm + filter	1.9	
Total	124	834

Table 2-17 summarizes total flue gas emissions for all components analyzed, including trace elements and ionic species. For these, within analytical accuracy, firing modes appears to have little overall effect on emission level. However, higher levels of organics ($>C_7$) and ammonium compounds were experienced with the BOOS test.

Ash stream composition data are shown in Tables 2-18 through 2-20. The data indicate that ash stream organic content increased with BOOS firing. Concentrations of the trace element and ionic species remain relatively unchanged with firing mode.

Crist Unit 7

The test program conducted on Crist Unit 7 encompassed testing under baseline operation and under two modes of BOOS firing (BOOS 1 and BOOS 2 as described in Section 2.2.1). NO_x reductions from baseline were 33 percent for the BOOS 1 test and 30 percent for the BOOS 2 test. Detailed test data are reported in Reference 2-22. A summary of results is given below.

The NO_x controls employed in these tests did not appear to cause any operating problems during the test program. Steam temperatures were maintained at 811 ± 3K (1000°F). No excessive slagging of the furnace was noted. In addition, low NO_x operation of the boiler did not require reduction of boiler load. Boiler output was maintained between 417 and 434 MW throughout the tests, well below the rated capacity of 500 MW.

Table 2-17. Flue Gas Composition ESP Outlet (µg/dscm): Kingston Unit 6

	Baseline	Bias	BOOS
NO_x	1.16×10^{6}	7.35×10^{5}	6.54×10^{5}
SO_2	4.18×10^{6}	3.5×10^{6}	4.21×10^{6}
SO_3	1.20×10^{4}	1.10×10^{4}	1.20×10^{4}
CO	3.07×10^{4}	4.58×10^{4}	3.19×10^{4}
CO_2	2.72×10^{8}	2.82×10^{8}	2.86×10^{8}
Particulate	6.3×10^{5}	6.7×10^{5}	4.3×10^{5}
Antimony	3.9	<2.7	<2.6
Arsenic	95	78	81
Barium	2.25×10^{3}	1.7×10^{3}	1.5×10^{3}
Beryllium	9	11	7.3
Bismuth	<53	<56	2.3×10^{2}
Boron	--	--	8.8×10^{2}
Cadmium	<2.3	<2.4	<2.1
Chromium	1.69×10^{3}	4.8×10^{2}	2.4×10^{3}
Cobalt	66	75	89
Copper	2.9×10^{2}	3.4×10^{2}	3.2×10^{2}
Iron	4.5×10^{4}	3.4×10^{4}	3.3×10^{4}
Lead	74	86	51
Manganese	2.4×10^{2}	1.3×10^{2}	1.9×10^{2}
Mercury	1.8	3.1	3.5
Molybdenum	1.5×10^{2}	<56	8.7×10^{2}
Nickel	8.4×10^{2}	1.0×10^{3}	1.5×10^{3}
Selenium	10	8.2	5.1
Tellurium	<4.1	<4	<3.7
Thallium	<2.6	<2.7	<2.1
Tin	<6.4	141	<5.1
Titanium	6.1×10^{3}	5.7×10^{3}	3.6×10^{3}
Uranium	<3.9	44	<2.1
Vanadium	2.6×10^{2}	2.3×10^{2}	1.6×10^{2}
Zinc	4.3×10^{2}	5.9×10^{2}	8.4×10^{2}
Zirconium	1.9×10^{2}	2.6×10^{2}	6.8×10^{2}
Chloride	2.7×10^{2}	4.1×10^{2}	8.6×10^{2}
Fluoride	84	3.5×10^{2}	1.2×10^{2}
Cyanide	<1.3	0.3	<1.3
Nitrate	<3.9	24	7.7×10^{2}
Sulfate	2.4×10^{4}	1.2×10^{4}	2.9×10^{4}
Ammonium	<5.3	7.2	1.5×10^{2}
Organics (>C7)	124	--	834

Table 2-18. Bottom Ash Composition (μg/g): Kingston Unit 6

	Baseline	Bias	BOOS
Antimony	< 3	< 3	< 3
Arsenic	4	5	3
Barium	2.4×10^3	2.6×10^3	2.0×10^3
Beryllium	10	10	10
Bismuth	< 70	< 70	< 70
Boron	< 16	< 16	< 16
Cadmium	< 3	< 3	< 3
Chromium	160	160	170
Cobalt	90	50	70
Copper	77	83	81
Iron	9.6×10^4	8.9×10^4	7.4×10^4
Lead	< 30	< 30	< 30
Manganese	280	170	200
Mercury	0.02	0.07	0.08
Molybdenum	< 70	< 70	< 70
Nickel	65	60	110
Selenium	< 2	< 2	< 2
Tellurium	20	8	6
Thallium	< 0.5	< 0.5	< 0.5
Tin	< 1	< 1	< 1
Titanium	9.2×10^3	9.2×10^3	9.1×10^3
Uranium	6	< 5	< 5
Vanadium	170	170	180
Zinc	37	31	35
Zirconium	420	340	330
Chloride	100	100	93
Fluoride	12	120	< 28
Cyanide	< 0.1	< 0.4	< 0.1
Nitrate	< 2	< 2	< 2
Sulfate	500	400	530
Ammonium	< 1	< 1	< 1
Organics $(>C_7)$	1.5	--	4.2

Table 2-19. Mechanical Hopper Ash Composition (μg/g): Kingston Unit 6

	Baseline	Bias	BOOS
Antimony	<3	<3	<3
Arsenic	40	35	40
Barium	3.0×10^3	2.4×10^3	2.9×10^3
Beryllium	10	10	12
Bismuth	<70	<70	<70
Boron	100	190	160
Cadmium	3	3	< 3
Chromium	170	160	190
Cobalt	60	60	60
Copper	115	105	134
Iron	7.8×10^4	4.9×10^4	7.6×10^4
Lead	< 30	30	< 30
Manganese	190	<130	140
Mercury	0.02	0.04	0.02
Molybdenum	<70	<70	<70
Nickel	65	55	70
Selenium	< 2	3	< 2
Tellurium	< 6	< 6	< 6
Thallium	< 0.5	< 0.5	< 0.5
Tin	2	1	< 1
Titanium	9.8×10^3	9.9×10^3	1.1×10^4
Uranium	6	< 5	6
Vanadium	240	230	230
Zinc	79	63	79
Zirconium	< 10	130	140
Chloride	140	170	90
Fluoride	28	8	11
Cyanide	< 0.1	< 0.1	< 0.4
Nitrate	< 2	< 2	< 2
Sulfate	1.7×10^3	1.0×10^3	1.3×10^3
Ammonium	< 1	22	2
Organics ($>C_7$)	1.3	--	3.2

Table 2-20. ESP Hopper Ash Composition (μg/g): Kingston Unit 6

	Baseline	Bias	BOOS
Antimony	< 3	< 3	< 3
Arsenic	130	100	120
Barium	2.8×10^3	3.2×10^3	2.9×10^3
Beryllium	12	14	13
Bismuth	<70	<70	<70
Boron	<16	<16	<16
Cadmium	< 3	< 3	< 3
Chromium	180	190	200
Cobalt	60	60	70
Copper	160	162	195
Iron	6.2×10^4	4.9×10^4	5.7×10^4
Lead	60	76	70
Manganese	200	160	160
Mercury	0.06	0.15	0.16
Molybdenum	90	<70	<80
Nickel	90	100	100
Selenium	3	4	3
Tellurium	< 6	< 6	< 6
Thallium	< 0.5	< 0.5	< 0.5
Tin	< 1	< 1	< 1
Titanium	9.8×10^3	1.0×10^4	1.0×10^4
Uranium	6	5	8
Vanadium	300	270	300
Zinc	180	170	190
Zirconium	<10	65	<10
Chloride	60	70	57
Fluoride	47	53	28
Cyanide	< 0.1	< 0.1	< 0.1
Nitrate	< 2	< 2	< 2
Sulfate	5.2×10^3	4.6×10^3	4.4×10^3
Ammonium	61	2	2
Organics $(>C_7)$	1.4	--	6.7

Boiler efficiency was not affected by firing mode except for a slight increase in the BOOS 2 test as shown in Table 2-21. This result was due to lowered excess air levels.

Table 2-22 shows flue gas vapor species concentration data for the three firing conditions. As noted, NO_x was reduced 33 percent in the BOOS 1 test and 30 percent in the BOOS 2 test. CO emissions increased by 70 percent under BOOS 1 firing but increased only slightly under BOOS 2 firing. SO_2 emissions varied with fuel sulfur content, which averaged 3.7, 3.9, and 3.4 respectively for the baseline, BOOS 1 and BOOS 2 tests, and not with firing mode. However, the fraction of fuel sulfur emitted as SO_3 decreased under BOOS firing.

Particulate testing showed that particulate emissions and ESP collection efficiency were not greatly affected by firing mode, as shown in Table 2-23. Also particle size distribution did not vary significantly.

Table 2-21. Boiler Efficiency: Crist Unit 7

	Baseline	BOOS 1	BOOS 2
Heat input (% of Baseline)	100	102	103
Excess O_2 (% of Baseline)	100	100	59
Efficiency (%)	86.2	87.0	88.0
Heat loss due to combustibles in flyash (%)	0.21	0.46	0.60
Heat loss due to dry flue gas (%)	7.0	6.4	5.3

Table 2-22. Flue Gas Composition: Crist Unit 7

	Baseline	BOOS 1	BOOS 2
NO_x, ng/J as NO_2	443	298	312
ppm[a]	725	488	510
SO_2, ng/J	2780	3250	2830
ppm[a]	3270	3820	3330
SO_3, ng/J	9.5	3.6	4.5
ppm[a]	8.9	3.4	4.3
CO, ng/J	133	226	146
ppm[a]	357	608	392
CO_2, % dry	13.4	13.3	16.0
O_2, % dry	3.2	3.3	2.0

[a] 3 percent O_2 dry

Table 2-23. Method 5 Particulate Concentration: Crist Unit 7

	Baseline	BOOS 1	BOOS 2
ESP Inlet, μg/J	9.8	4.1	3.8
ESP Outlet, μg/J	0.46	0.36	0.34
ESP Collection Efficiency (%)	90	91	91
Inlet Concentration (g flyash/g ash in coal)	0.73	0.87	0.69

Table 2-24 shows the summary Level 1 organic analysis results for flue gas SASS samples taken downstream of the ESP. Within the accuracy of the analyses, there was no significant difference in the level of organic emissions among the tests. Infrared analysis of the samples indicated the presence of aliphatic hydrocarbons, ether, and possibly carboxylic acids in all samples.

Table 2-24. SASS Sample Organic Analysis Results (mg/dscm): Crist Unit 7

Sample	Baseline	BOOS 1	BOOS 2
XAD-2 Extract	4.3	0.72	2.2
Flyash	0.004	0.005	0.18
Total	4.3	0.72	2.3

Table 2-25 summarizes the results of the GC/MS analysis of flue gas SASS samples taken at the ESP outlet. A few POM species were found at low concentration, and evidence of sample phthalate contamination was apparent.

Table 2-26 summarizes total flue gas emissions for all components analyzed, including trace elements and ionic species. For these latter species, within analytical accuracy, firing mode appears to have little effect on emission levels.

Ash stream composition data are shown in Tables 2-27 and 2-28. The data indicate that bottom ash organic content decreased with BOOS firing. Infrared analysis of ash organic extracts indicate the presence of aliphatic hydrocarbons, ether, alcohols, and possibly carboxylic acids. Data from the GC/MS analyses of bottom ash stream organic extracts showed only evidence of phthalate contamination. Within analytical accuracy, firing mode did not appear to influence emission levels of trace element or ionic species.

Table 2-25. SASS Sample GC/MS Results (μg/dscm): Crist Unit 7

Compound	Baseline			BOOS 1			BOOS 2		
	XAD-2 Extract	Flyash	Total	XAD-2 Extract	Flyash	Total	XAD-2 Extract	Flyash	Total
Benzoic acid	--	--	--	--	--	--	50	--	50
Bis (2-ethylhexyl) phthalate	4.0	11.0	15.0	50	5.0	55	50	2.0	52
Chrysene/Benz (a) anthracene	--	--	--	0.10	--	0.10	--	--	--
Dichlorobenzene	--	--	--	0.20	--	0.20	0.20	--	0.20
Dimethyl phthalate	--	--	--	0.20	--	0.20	50	--	50
Fluoranthene	0.10	--	0.10	0.20	--	0.20	0.10	--	0.10
Fluorene	--	--	--	0.30	--	0.30	--	--	--
Naphthalene	--	--	--	--	0.30	0.30	0.50	0.40	0.90
Phenanthrene/ anthracene	0.10	0.10	0.20	0.60	0.30	0.90	0.80	0.20	1.0
Pyrene	0.10	--	0.10	0.30	--	0.30	0.30	--	0.30

Table 2-26. Flue Gas Composition ESP Outlet (μg/dscm): Crist Unit 7

	Baseline	BOOS 1	BOOS 2
NO_x	9.8×10^5	5.9×10^5	8.3×10^5
SO_2	6.2×10^6	6.5×10^6	6.2×10^6
SO_3	2.1×10^4	7.2×10^3	1.2×10^4
CO	2.9×10^5	4.5×10^5	3.9×10^5
CO_2	1.7×10^8	1.5×10^8	2.5×10^8
Particulate	1.0×10^6	7.2×10^5	9.1×10^5
Antimony	11	4.8	12
Arsenic	51	53	50
Barium	2.6×10^3	990	2.3×10^3
Beryllium	14	10	11
Bismuth	<4.5	160	<6.4
Boron	2.2×10^3	2.7×10^3	2.6×10^3
Cadmium	6.3	8.4	4.3
Chromium	3.6×10^3	6.5×10^3	440
Cobalt	170	110	140
Copper	99	41	95
Iron	2.3×10^4	1.5×10^5	2.9×10^4
Lead	100	66	89
Manganese	1.3×10^3	790	860
Mercury	<17	32	21
Molybdenum	280	78	72
Nickel	1.6×10^3	2.8×10^3	1.3×10^3
Selenium	77	<50	73
Tellurium	<4	<1.4	<4.4
Thallium	<430	<290	<370
Tin	8.5	7.5	<7.8
Titanium	3.7×10^3	3.6×10^3	5.3×10^3
Vanadium	300	380	260
Zinc	580	240	600
Chloride	14	19	--
Fluoride	1.4	1.3	--
Cyanide	<0.05	<0.04	--
Nitrate	4.1	11	--
Sulfate	2.6×10^4	1.6×10^4	2.6×10^4
Ammonium	2.9	0.61	--
Organics (>C_7)	4.3×10^3	720	2.3×10^3
Benzoic acid	--	--	50
Chrysene/Benz(a)anthracene	--	0.1	--
Dichlorobenzene	--	0.2	0.2
Fluoranthene	0.1	0.2	0.1
Fluorene	--	0.3	--
Naphthalene	--	0.3	0.9
Phenanthrene/anthracene	0.2	0.9	1.0
Pyrene	0.1	0.3	0.3

Bioassays were performed on selected samples from the BOOS 2 test. All samples had nondetectable toxicity in all bioassays except the combined 1 m and filter sample from the ESP outlet. This sample was found to have low toxicity in the Rabbit Alveolar Macrophage test. The bioassay results are presented in Table 2-29.

Table 2-27. Bottom Ash Composition (μg/g): Crist Unit 7

	Baseline	BOOS 1	BOOS 2
Antimony	<0.6	<0.6	<0.6
Arsenic	<3	<8	<3
Barium	270	770	160
Beryllium	9	6.5	7.7
Bismuth	<6	230	<6
Boron	<0.1	0.2	0.2
Cadmium	<0.030	0.40	<0.030
Chromium	75	100	74
Cobalt	5	<0.1	2
Copper	60	23	53
Iron	4.1 x 10^4	1.9 x 10^5	4.3 x 10^4
Lead	34	23	21
Manganese	890	1.1 x 10^3	970
Mercury	<0.6	<0.6	<0.7
Molybdenum	<6	<3	<0.6
Nickel	54	48	53
Selenium	0.70	1	2.50
Tellurium	<0.90	0.40	<0.9
Thallium	<400	<400	<400
Tin	<2	<4	<2.0
Titanium	2.4 x 10^3	5.1 x 10^3	2.3 x 10^3
Vanadium	240	340	220
Zinc	150	310	190
Organics (>C_7)	125	12.1	16.6

Table 2-28. ESP Hopper Ash Composition (μg/g): Crist Unit 7

	Baseline	BOOS 1	BOOS 2
Antimony	< 0.5	< 0.7	< 0.5
Arsenic	< 3	20	< 3
Barium	190	1.2×10^3	59
Beryllium	7.4	9.0	6.5
Bismuth	< 6.0	570	7
Boron	370	390	390
Cadmium	4.1	1.6	1.4
Chromium	130	120	110
Cobalt	< 2	18	< 2
Copper	48	42	45
Iron	3.3×10^4	1.6×10^5	2.8×10^4
Lead	62	60	68
Manganese	1.2×10^3	1.2×10^3	600
Mercury	< 0.8	< 0.7	0.90
Molybdenum	< 6	< 3.0	24
Nickel	150	46	89
Selenium	1	1.0	2.8
Tellurium	< 0.9	< 0.2	< 0.9
Thallium	< 400	< 400	< 400
Tin	3	< 5.0	< 2.0
Titanium	4.0×10^3	5.4×10^3	2.6×10^3
Vanadium	230	360	210
Zinc	210	260	150
Zirconium	170	140	--
Chloride	23	29	< 5.2
Fluoride	10	2.8	2.0
Cyanide	< 0.1	< 0.1	< 0.1
Nitrate	14	5.6	43
Sulfate	196	263	212
Ammonium	2.3	5.8	5.4
Organics ($>C_7$)	< 4.9	< 4.9	< 4.9

Table 2-29. Bioassay Results: Crist Unit 7

Sample	Salmonella Mutagenicity (Ames)	Rabbit Alveolar Macrophage (RAM)	Rat Oral Toxicity	Freshwater Algal Bioassay	Freshwater Fish Toxicity
Boiler Bottom Ash	ND	ND	ND	ND	ND
ESP Hopper Ash	ND	ND[a]	ND	ND	ND
SASS Train (10 μm + 3 μm particles)	ND	ND	--	--	--
SASS Train (1 μm + filter)	ND	L	--	--	--

ND -- No detectable results under the parameters of experiment
L -- Low toxicity
[a] Although declared nondetectable, Litton Bionetics reported that all assay parameters (particularly ATP and ATP/10^6 cells) decreased relative to the negative control for concentrations of test material greater than about 300 μg/ml

2.5.1.2 Oil-Fired Utility Boiler

Moss Landing Unit 6

The test program conducted on Moss Landing Unit 6 encompassed testing under uncontrolled operation (baseline) and under two modes of NO_x controlled operation: flue gas recirculation through the windbox (FGR) and combined FGR and BOOS, with eight of 48 burners removed from service (see Section 2.2.1.2). This unit normally operates in the BOOS/FGR controlled condition, so controls were progressively removed in this test program. The fuel fired in the tests was a 1:1 mixture of crude oil and residual oil. Detailed test results are presented in Reference 2-23. Test data obtained are summarized below.

Boiler efficiency for each of the tests is shown in Table 2-30. As can be seen from the table, efficiency and heat rate remained fairly constant for all tests. Thus, BOOS/FGR and FGR appeared to not affect unit efficiency.

Table 2-30. Boiler Efficiency: Moss Landing Unit 6

	Baseline	FGR	BOOS/FGR
Heat input (% of Baseline)	100	99	102
Excess O_2 (% of Baseline)	100	82	117
Efficiency (%)	88.0	88.0	88.1
Heat loss due to dry flue gas (%)	3.84	3.75	3.76
Heat rate $\frac{(\text{Electrical output, MW})}{\text{Heat input, MW}}$	0.40	0.41	0.40

Table 2-31 shows flue gas concentration data for the three firing conditions. As the table shows, NO_x emissions were reduced 26 percent with FGR only and 43 percent with BOOS/FGR. Flue gas CO was also reduced under NO_x controlled firing with flue gas recirculation. Particulate and sulfur species emissions remained relatively constant with firing condition, although SO_3 emissions may have increased in the BOOS/FGR test, possibly because of the higher excess air level used in this test.

Table 2-32 summarizes the results of the organic analyses performed in the tests. The data show that total organic ($>C_7$) emissions were highest under baseline firing. However, low molecular weight hydrocarbon ($<C_7$) emissions and POM species emissions were highest under BOOS/FGR firing. POM emissions in all cases, though, were quite low. Evidence of sample phthalate contamination was apparent.

Table 2-31. Flue Gas Composition: Moss Landing Unit 6

	Baseline	FGR	BOOS/FGR
NO_x, ng/J as NO^2	169	125	96
ppm[a]	301	222	172
SO_2, ng/J	119	129	123
ppm[a]	153	165	158
SO_3, ng/J	1.9	1.9	2.7
ppm[a]	1.9	1.9	2.8
$SO_4{}^=$ (condensed), ng/J	3.2	3.3	2.6[b]
Particulate, ng/J	23	22	16
CO, ng/J	26	3.7	18
ppm[a]	69	10	49
CO_2, %	13.0	13.5	12.8
O_2, %	3.3	2.8	3.7

[a] 3 percent O_2, dry
[b] Only one duct sampled

Table 2-32. Flue Gas Organic Composition ($\mu g/m^3$):
Moss Landing Unit 6

	Baseline	FGR	BOOS/FGR
C_1 to C_6 HC (as CH_4)	--	--	40
Total $>C_7$ organic	4380	1370	1430
Bis (2-ethylhexyl) phthalate	--	5.0	120
Chrysene/Benz(a)anthracene	--	--	0.10
Dichlorobenzene	--	--	0.10
Fluoranthene	--	0.10	0.10
Fluorene	--	--	0.10
Pyrene	--	--	0.20

Infrared analysis of organic extracts showed aliphatic hydrocarbons, ethers, and possibly carboxylic acids in all test extracts. Nitriles and imides or anhydrides were evidenced in the baseline and FGR extracts and evidence of aromatics was noted in the BOOS/FGR extract.

Table 2-33 summarizes total flue gas emissions for all components analyzed, including trace elements and ionic species. For these latter species, within analytical accuracy, firing mode appears to have little effect on emissions levels.

Mutagenicity and cytotoxicity evaluations of the flue gas organic extract from the BOOS/FGR test were performed. The microbial mutagenesis assay results did not show any mutagenic or toxic results. The WI-38 cytotoxicity assay showed moderate toxicity.

2.5.2 Industrial Boilers

Two coal-fired traveling grate spreader stoker industrial boilers were tested in the NO_x EA field test program (References 2-24 and 2-25). Both tests were cooperative efforts with KVB, Inc. in their program on stoker emissions control and efficiency improvement. The results of these tests are discussed below. Further tests on these units are documented in the KVB reports on Site A (Reference 2-26) and Site B (Reference 2-27). Details on these units are given in Section 2.2.1.3.

Stoker Site A

The test program at Site A encompassed testing under increased overfire air conditions (OFA -- Low NO_x) and under normal operating conditions (baseline). Summaries of the effects on boiler operation and emissions are given below. A detailed summary of test program results is given in Reference 2-24.

Increased OFA caused apparent operating efficiency to increase from 77.8 percent to 80.8 percent. The largest contributing factor to the increase in efficiency was the decrease of combustible material in the flyash. Efficiency results are presented in Table 2-34.

Table 2-33. Flue Gas Composition (μg/dscm): Moss Landing Unit 6

	Baseline	FGR	BOOS/FGR
NO_x	5.8×10^5	4.4×10^5	3.3×10^5
SO_2	4.1×10^5	4.6×10^5	4.2×10^5
SO_3	6.6×10^3	6.8×10^3	9.3×10^4
CO	8.1×10^4	1.2×10^4	5.7×10^5
CO_2	2.4×10^8	2.6×10^8	2.3×10^8
Particulate	7.9×10^5	5.5×10^5	7.8×10^5
Antimony	1.0	1.5	0.64
Arsenic	8.5	8.4	7.6
Barium	170	120	93
Beryllium	<0.3	<0.19	<0.24
Bismuth	<1.8	<1.4	<1.3
Boron	5.1×10^3	2.6×10^4	2.4×10^3
Cadmium	<41	<0.06	<10
Chromium	110	150	99
Cobalt	58	56	37
Copper	59	1.5×10^3	600
Iron	570	800	420
Lead	0.10	0.07	0.054
Manganese	53	58	46
Mercury	0.16	0.068	0.089
Molybdenum	9.8	10	7.1
Nickel	91	4.8×10^3	1.3×10^3
Selenium	0.20	0.13	0.33
Tellurium	<0.04	<0.039	<0.029
Thallium	<0.99	<0.71	<0.72
Tin	<0.04	<0.039	<0.029
Titanium	1.5	<1.1	<1.1
Vanadium	500	490	340
Zinc	230	170	130
Sulfate	1.1×10^4	1.2×10^4	8.9×10^3
Organics ($>C_7$)	4.4×10^3	1.4×10^3	1.5×10^3
Methane	--	--	40
Chrysene/Benz(a) anthracene	--	--	0.10
Dichlorobenzene	--	--	0.10
Fluoranthene	--	0.10	0.10
Fluorene	--	--	0.10
Pyrene	--	--	0.20

Table 2-34. Boiler Efficiency (%): Stoker Site A

Heat Loss	Baseline	Low NO_x[a]
Dry gas	8.7	8.3
Moisture in fuel	1.6	1.7
H_2O from H_2 combustion	4.4	4.3
Combustibles in refuse	4.9	2.3
Radiation	1.1	1.1
Unmeasured	1.5	1.5
Total loss	22.2	19.2
Efficiency	77.8	80.8

[a] Low excess air and overfire air

Table 2-35 shows flue gas vapor species concentration data at the ESP outlet for the two firing conditions. As noted, NO_x emissions were reduced 18 percent under low NO_x conditions. Emission levels of CO, SO_2, and SO_3 all increased under low NO_x firing. However, the increases in sulfur species emissions were probably due to measurement difficulties or inhomogeneities in coal composition, rather than due to changes in firing mode.

Table 2-36 shows particulate load data at the boiler outlet and the ESP outlet. As the table shows, particulate load decreased at the boiler outlet for low NO_x firing, but increased at the ESP outlet, with a corresponding decrease in overall (air heater hopper, mechanical collector, ESP) particle collection efficiency.

Table 2-37 shows summary organic analysis results of the flue gas and flue gas SASS samples taken at the ESP outlet. As noted flue gas organic (C_7) emissions increased under low NO_x firing. Infrared analysis results of sample extracts indicated the presence of carboxylic acids and some aromatics in the baseline extract, and aromatics and possibly an amide in the low NO_x extract.

Table 2-35. Flue Gas Composition at ESP Outlet: Stoker Site A

	Baseline	Low NO_x[b]
NO_x, ng/J as NO_2	233	192
ppm[a]	382	315
SO_2, ng/J	305	383
ppm[a]	353	479
SO_3, ng/J	7.2	12
ppm[a]	2.0	12
CO, ng/J	90	180
ppm[a]	243	483
O_2, % dry	6.4	6.5

[a] 3 percent O_2, dry.
[b] Low excess air and overfire air

Table 2-36. Method 5 Particulate Concentration: Stoker Site A

	Baseline	Low NO_x[a]
Boiler Outlet		
g/J	9.86	5.76
g/dscm	26.9	14.5
ESP Outlet		
g/J	0.013	0.024
g/dscm	0.040	0.063
Overall Collection Efficiency (%)	99.85	99.57

[a] Low excess air and overfire air

Table 2-37. Organic Analysis Results (mg/dscm):
Stoker Site A

	Baseline	Low NO_x[b]
C_1 - C_6 HC (as CH_4)	48.9	-[a]
Total >C_7 Organics	1.00	1.79

[a] Data not available

[b] Low excess air and overfire air

Table 2-38 summarizes flue gas emissions for all components analyzed, including trace elements. For these latter species, within analytical accuracy, emission levels generally remain relatively unchanged with firing mode.

Ash steam composition data are shown in Tables 2-39 through 2-41. As the tables show, ash trace element composition did not vary with firing condition. It is interesting to note, though that bottom ash nitrate levels (oxidized nitrogen) apparently decreased, and ammonium (reduced nitrogen) levels increased for the low NO_x test. In addition, organic species levels were higher in the low NO_x bottom ash than in the baseline bottom ash, although the baseline mechanical hopper ash had higher organic content than the low NO_x mechanical hopper ash.

Infrared analyses of ash sample extracts indicated that carboxylic acids, esters, or ethers were present in bottom ash samples, and that only aliphatic hydrocarbons were present in ESP hopper ash samples. No information on the organic speciation of mechanical hopper ash samples could be derived because IR spectra obtained were weak.

Stoker Site B

The test program at Site B encompassed testing under normal (baseline) and low excess air (low NO_x) operation. Low NO_x operation achieved a 37 percent reduction in NO_x at the economizer outlet. Summaries on the effects of low excess air (LEA) firing on boiler operation and emissions are given in the following. A detailed summary of test program results is given in Reference 2-25.

Table 2-38. Flue Gas Composition at the ESP Outlet (μg/dscm): Stoker Site A

	Baseline	Low NO_x[a]
NO_x	6.3×10^5	5.2×10^5
SO_2	8.2×10^5	1.1×10^6
SO_3	5.8×10^3	3.5×10^4
CO	2.5×10^5	4.8×10^5
Particulate	4.0×10^4	6.3×10^4
Antimony	< 19	< 3.2
Arsenic	3.2	< 7.0
Barium	420	70
Beryllium	3.8	< 0.097
Bismuth	< 24	< 6.7
Boron	91	350
Cadmium	6.1	< 17
Chromium	17	150
Cobalt	9.2	< 48
Copper	29	< 98
Iron	1.1×10^3	1.9×10^3
Lead	< 57	< 180
Manganese	32	< 77
Mercury	< 0.037	< 0.016
Molybdenum	10	< 8.0
Nickel	34	< 140
Selenium	32	45
Tellurium	1.1	< 5.5
Thallium	< 34	< 370
Tin	8.4	< 220
Titanium	1.2	580
Vanadium	8.7	< 17
Zinc	63	35
Organics ($>C_7$)	$1.0 \times 10_3$	1.8×10^3
Methane	4.9×10^4	--

[a] Low excess air and overfire air

Table 2-39. Bottom Ash Composition (μg/g):
Stoker Site A

	Baseline	Low NO_x[a]
Antimony	< 0.6	< 0.7
Arsenic	2	3
Barium	240	150
Beryllium	0.8	1.3
Bismuth	< 40	< 40
Boron	< 5	< 5
Cadmium	< 1	< 1
Chromium	24	26
Cobalt	< 5	< 6
Copper	42	35
Iron	3.0×10^4	3.1×10^4
Lead	< 20	< 20
Manganese	540	560
Molybdenum	< 1	< 2
Nickel	8	< 7
Selenium	< 0.4	2.10
Tellurium	< 0.8	< 0.9
Thallium	< 50	< 60
Tin	520	390
Titanium	4.2×10^3	4.0×10^4
Vanadium	< 20	< 20
Zinc	17	19
Chloride	< 32.9	< 36
Fluoride	5.58	6.10
Cyanide	< 2.65	< 2.90
Nitrate	3.17×10^4	1.45×10^4
Sulfate	26	19
Ammonium	23.1	97
Organics ($>C_7$)	< 1.9	33.3

[a] Low excess air and overfire air

Table 2-40. Mechanical Hopper Ash Composition (μg/g): Stoker Site A

	Baseline	Low NO_x[a]
Antimony	< 0.6	< 0.6
Arsenic	2	2
Barium	9	9
Beryllium	0.54	0.97
Bismuth	< 40	< 40
Boron	< 4	< 4
Cadmium	< 1	< 1
Chromium	3.1	5.9
Cobalt	< 5	< 5
Copper	8	15
Iron	3.3×10^3	6.7×10^3
Lead	< 20	< 20
Manganese	70	150
Molybdenum	< 1	< 1
Nickel	< 6	11
Selenium	1	1.5
Tellurium	< 0.8	< 0.8
Thallium	< 50	< 50
Tin	2	2
Titanium	350	810
Vanadium	< 20	< 20
Zinc	4	10
Chloride	< 37	< 30
Fluoride	19	48
Cyanide	< 3	< 2.8
Nitrate	--	9.2×10^4
Sulfate	< 6	37
Ammonium	23	18
Organics (>C_7)	330	< 12

[a] Low excess air and overfire air

Table 2-41. ESP Hopper Ash Composition (μg/g): Stoker Site A

	Baseline	Low NO_x[a]
Antimony	4.3	5.2
Arsenic	36	38
Barium	120	140
Beryllium	5	4.8
Bismuth	< 40	< 40
Boron	< 4	< 4
Cadmium	< 1	3
Chromium	27	34
Cobalt	27	21
Copper	120	140
Iron	2.6×10^4	2.4×10^4
Lead	110	120
Manganese	550	500
Molybdenum	7	8
Nickel	53	50
Selenium	5.5	6.8
Tellurium	< 0.8	< 0.80
Thallium	< 50	< 50
Tin	8	8
Titanium	4.0×10^3	3.6×10^3
Vanadium	30	35
Zinc	350	390
Chloride	< 39	< 34
Fluoride	6.9	15
Cyanide	< 3.1	< 2.8
Nitrate	9.9×10^3	3.1×10^4
Sulfate	220	83
Ammonium	28	49
Organics ($>C_7$)	76	71

[a] Low excess air and overfire air

Low excess air firing did not appear to cause any operating problems in these tests. Steam temperatures and pressures were maintained at 533K (500^{0}F) and 1.4 MPa (190 psig) respectively and clinkering was not a problem. Still, these tests were of 5 to 6 hours duration, thus the potential long-term effects of low NO_x firing could not be evaluated.

Table 2-42 shows the results of boiler efficiency calculations. As noted, unit efficiency improved slightly with LEA firing. This was due to a decrease in dry gas loss without an offsetting loss due to combustibles in the flyash.

Table 2-42. Boiler Efficiency: Stoker Site B

	Baseline	Low Excess Air
Heat input (percent Baseline)	100	102
Excess O_2 (percent Baseline)	100	46
Efficiency	79.9	81.6
Heat loss due to combustibles in ash (percent)	4.9	5.8
Heat loss due to dry flue gas (percent)	9.4	7.0

Table 2-43 shows flue gas vapor species concentration data at the economizer outlet for the two firing conditions. As noted, NO_x emissions decreased 37 percent under LEA operation, while CO levels remained relatively unchanged. This is because CO levels were deliberately held below 65 ppm throughout the test program. This was done by reducing the excess air level until increases in CO were seen, then increasing the excess air level slightly to provide a comfortable operating margin.

Table 2-43. Flue Gas Composition at Economizer Outlet: Stoker Site B

	Baseline	Low[c] NO_x
NO_x, ng/J as NO_2	210	131
ppm[a]	343	215
SO_2[b], ng/J	227	105
ppm[a]	272	149
SO_3[b], ng/J	1.0	0.7
ppm[a]	1.0	0.8
CO, ng/J	24	13
ppm[a]	65	36
CO_2, % dry	11.6	13.2
O_2, % dry	8.1	6.0

[a] 3 percent O_2, dry.
[b] By Shell-Emeryville method at ESP outlet: may be in error
[c] Low excess air

Results of the sulfur species analyses were inconclusive in that errors in the concentration values obtained by the Shell-Emeryville method used were suspected.

Particulate testing showed that LEA firing resulted in only slightly greater particulate emissions, as shown in Table 2-44. ESP collection efficiency may have been slightly lower in the low NO_x test.

Table 2-45 shows summary organic analysis results of the flue gas, and flue gas SASS samples taken at the ESP outlet. As the table shows, flue gas organic emissions did show an increase with low NO_x firing. Infrared analysis of the sample extracts indicated the presence of aliphatic hydrocarbons, ethers, esters, and carboxylic acids in the extracts from both tests.

Table 2-44. Method 5 Particulate Concentration ($\mu g/J$): Stoker Site B

	Baseline	Low NO_x [a]
Boiler Outlet	7.31	5.82
ESP Outlet	0.008	0.010
Overall Collection Efficiency (%)	99.89	99.83

[a] Low excess air

Table 2-45. Organic Analysis Results (mg/dscm): Stoker Site B

	Baseline	Low NO_x
C_1 - C_6 HC (as CH_4)	12.7	57.2
Total $> C_7$ Organics	0.92	1.37

Table 2-46 summarizes flue gas emissions for all species analyzed, including trace elements. For these latter species, no real trends in emission levels with firing mode were apparent.

Ash stream composition data are shown in Tables 2-47 through 2-49. The tables show that, within analytical accuracies, ash trace element or organic concentrations did not vary significantly with firing mode. Infrared analyses of ash sample extracts indicated the presence of aliphatic and aromatic hydrocarbons, esters, and carboxylic acids in the bottom ash sample, aliphatics in the mechanical collector hopper ash sample, and possibly an ester or carboxylic acid in the ESP hopper ash samples.

Table 2-46. Flue Gas Composition at ESP Outlet (μg/dscm): Stoker Site B

	Baseline	Low NO_x[a]
NO_x	4.7×10^5	3.4×10^5
SO_2	5.2×10^5	3.3×10^5
SO_3	2.4×10^3	2.2×10^3
CO	5.4×10^4	3.5×10^4
CO_2	2.1×10^8	2.4×10^8
Particulate	1.9×10^4	2.9×10^4
Antimony	3.5	3.5
Arsenic	35	39
Barium	170	2.7
Beryllium	1.2	0.25
Bismuth	2.6	3.2
Boron	$<6.8 \times 10^3$	7.8×10^3
Cadmium	<1.2	5.2
Chromium	61	20
Cobalt	23	5.8
Copper	64	0.050
Iron	280	<71.2
Lead	<1.2	<0.5
Manganese	12	11
Mercury	2.4	1.3
Molybdenum	320	210
Nickel	2.6×10^3	2.4×10^3
Selenium	13	13
Tellurium	2	<3
Thallium	2	<2.2
Tin	9.5	<8.8
Titanium	<55	<49
Vanadium	130	18
Zinc	9.7	<0.058
Organics ($>C_7$)	920	1.4×10^3
Methane	1.3×10^4	5.7×10^4

[a] Low excess air

Table 2-47. Bottom Ash Composition (μg/g): Stoker Site B[a]

	Low NO_x[b]
Antimony	< 0.6
Arsenic	< 2
Barium	< 10
Beryllium	< 0.2
Bismuth	19
Boron	$< 2 \times 10^3$
Cadmium	0.84
Chromium	110
Cobalt	16
Copper	96
Iron	2.0×10^4
Lead	5.8
Manganese	460
Mercury	< 0.7
Molybdenum	< 3
Nickel	48
Selenium	< 0.3
Tellurium	3.5
Thallium	< 3
Tin	210
Titanium	8.9×10^3
Vanadium	190
Zinc	11
Chloride	< 19.8
Fluoride	< 0.1
Cyanide	< 2.5
Nitrate	2.7
Sulfate	360
Ammonium	9.1
Organics (>C_7)	120
Alkanes	15
Fluoranthene	0.015
Phenanthrene/anthracene	0.60

[a] Baseline sample not taken

[b] Low excess air

Table 2-48. Mechanical Collector Hopper Ash Composition (μg/g): Stoker Site B

	Baseline	Low NO_x[a]
Antimony	<0.6	<0.6
Arsenic	2	<2
Barium	83	370
Beryllium	24	3
Bismuth	<0.8	<1
Boron	5.0×10^3	$<2.0 \times 10^3$
Cadmium	<0.030	0.49
Chromium	9.0×10^3	64
Cobalt	34	<0.1
Copper	46	24
Iron	1.4×10^4	8.0×10^3
Lead	420	6.9
Manganese	310	250
Mercury	<0.09	<0.7
Molybdenum	<0.5	<3
Nickel	40	30
Selenium	<1	<0.3
Tellurium	<0.6	0.5
Thallium	<5	<3
Tin	200	62
Titanium	2.4×10^3	1.4×10^3
Vanadium	54	7.1
Zinc	24	22
Chloride	<19.9	<20
Fluoride	2.60	6.20
Cyanide	<2.5	<2.5
Nitrate	<0.3	<0.3
Sulfate	1.24×10^3	849
Ammonium	<2.50	<2.5
Organics ($>C_7$)	61	6

[a] Low excess air

Table 2-49. ESP Hopper Ash Composition (μg/g): Stoker Site B

	Baseline	Low NO_x[a]
Antimony	27	31
Arsenic	740	590
Barium	4.4×10^3	2.8×10^3
Beryllium	77	69
Bismuth	< 0.6	11
Boron	$< 2.0 \times 10^3$	2.7×10^3
Cadmium	1	3
Chromium	< 0.4	< 0.3
Cobalt	< 0.03	< 0.02
Copper	0.62	0.76
Iron	30	31
Lead	< 0.09	< 0.09
Manganese	0.21	0.26
Mercury	0.20	0.20
Molybdenum	21	26
Nickel	< 0.7	< 0.6
Selenium	84	120
Tellurium	< 0.5	< 0.4
Thallium	< 4	< 4
Tin	33	45
Titanium	14	8.5
Vanadium	4.6	3.8
Zinc	0.57	0.82
Chloride	< 20	< 19.9
Fluoride	38	62.2
Cyanide	< 0.15	< 0.56
Nitrate	1.8	4.8
Sulfate	1.1×10^4	2.3×10^4
Ammonium	0.18	450
Organics ($>C_7$)	73	260

[a] Low excess air

Bioassays were performed on the bottom ash and ESP hopper ash from the low NO_x test. Results are shown in Table 2-50. As the table shows negative mutagenicity and nondetectable toxicity results were the rule. Only the ESP hopper ash elicited a positive response, giving a low toxicity result in the RAM assay.

2.5.3 Gas Turbine

One gas turbine was tested in the NO_x EA: an oil-fired utility gas turbine at Houston Lighting and Power's T. H. Wharton Station. This machine was equipped with a water injection system for NO_x control (see Section 2.2.1.4). A description of the site tested was given in Section 2.1. The test program conducted on this engine encompassed testing under base load operation at 62 MW of generator output. The first test run, at baseline conditions, was run with no water injection. The second test was run at a water injection rate sufficient to give NO_x emissions less than 75 ppm at 15 percent O_2, dry. Details of the test data taken are given in Reference 2-28. A summary of the effects of water injection on turbine operation and emissions follows.

Unit operation was held essentially constant throughout each test. The operating conditions listed in Table 2-51 show that the basic difference between tests was the water injection rate with the subsequent 2.4 percent increase in plant heat rate. A 0.42 water-to-fuel ratio was required to reduce NO_x emissions from 177.5 to 74.2 ppm (15 percent O_2, dry).

Table 2-50. Bioassay Results: Stoker Site B Low NO_x Samples

Sample	Test				
	Microbial Mutagenesis	RAM Cytotoxity	RAT	Freshwater Algae	Freshwater Fish
Bottom Ash	Neg	ND	ND	ND	ND
ESP Hopper Ash	Neg	L	ND	--	--

Table 2-51. Operating Conditions

	Baseline	Injection
Ambient barometric pressure -- mm Hg (in. Hg)	755 (29.74)	756 (29.79)
Ambient temperature -- dry bulb -- K (°F)	295 (71.2)	301 (82.0)
Relative humidity	83.6	58.7
Compressor discharge pressure P_{CD} -- kpa (psia)	915 (132.7)	901 (130.7)
Compressor discharge temperature T_{CD} -- K (°F)	593 (607)	602 (624)
Speed (rpm)	3600	3600
Inlet guide vane angle (IGV degrees)	77	77
Load (MW)	61.9	61.5
Turbine exhaust temperature -- K (°F)	809 (997)	813 (1000)
Water injection rate -- ℓ/s	0	2.52 (40)
Water/fuel ratio (kg/kg)	0	0.42
Fuel temperature -- K (°F)	295.4 (71.7)	298 (76.4)
Fuel flow -- ℓ/s (gpm)	5.93 (94.0)	6.03 (95.6)
Atomizing air pressure -- kpa (psia)	1372 (199)	1372 (199)
Atomizing air temperature -- K (°F)	473 (392)	471 (387)
Combustion efficiency (percent)	99.9	99.9
Exhaust flow -- m^3/S (10^6 SCFH)	205.4 (26.14)	200.9 (25.52)
Compressor inlet flow -- kg/s (lbm/sec)	253 (556.7)	255.7 (562.7)
Fuel/air ratio	0.0190	0.0196
Heat rate -- MJ/kWh (Btu/kWh -- based on LHV)	12.55 (11,890)	12.84 (12,170)
Percent decrease in efficiency based on fuel consumption	NA	2.1

Table 2-52 shows flue gas composition data at the unit outlet for each firing condition tested. The table shows that CO and hydrocarbon emissions may have increased with water injection. Emissions of other species remained relatively unchanged.

Table 2-52. Flue Gas Composition: T. H. Wharton Unit 52

	Baseline	Water Injection
NO_x, ng/J as NO_2	319	128
ppm[a]	175.5	74.2
SO_2, ng/J	29	30
ppm[a]	11.7	12.7
SO_3, (vapor), ng/J	3.0	5.0
ppm[a]	1.1	1.8
$SO_4^=$ (condensed), ng/J	4.0	--
Particulate, ng/J	19	16
UHC, ng/J as CH_4	1.5	2.2
ppm[a]	2.7	4.0
CO, ppm[a]	5.6	8.1
CO_2, % dry	4.1	4.3
O_2, % dry	15.3	15.1

[a] 15 percent O_2, dry.

Table 2-53 shows summary Level 1 organic analysis results from the SASS train samples taken at the unit outlet. Three conclusions can be drawn from these results. First, virtually all of the organics in the flue gas can be found in compounds with the boiling point ranging from 373K to 573K. Second, there is little effect on the distribution of compounds, with regard to the boiling point, between the baseline and water injection test. Third, the use of water injection has a very small effect on the total amount of organics in the sample extract.

Table 2-54 shows the results of analyses for specific POM species by GC/MS. The data in the table indicate the presence of some POM compounds, phenols, and phthalate contaminants, all at low levels.

Table 2-53. Organic Analysis Results (mg/m^3): T. H. Wharton Unit 52

	Baseline	Water Injection
TCO[a] Organics	1.30	1.10
Gravimetric[b] Organics	0.030	0.004
Total	1.33	1.10

[a] TCO: Compounds in 373 to 537K boiling range
[b] Gravimetric: Compounds in >573K boiling range

Table 2-54. GC/MS Results (μg/m^3): T. H. Wharton Unit 52

	Baseline	Water Injection
Bis (2-ethylhexyl) phthalate	1.0	1.0
Other phthalates	1.0	1.0
Diphenyl ether	0.5	--
Diphenylcyclohexane	--	10.0
Fluoranthene	--	0.50
Naphthalene	--	1.0
Phenanthrene/Anthracene	0.50	1.0
Phenol	1.0	1.0
Pyrene	--	0.50
Terphenyl	--	5.0

Table 2-55 summarizes flue gas emissions for all species analyzed, including trace elements. For these latter species no apparent effect on water injection on emission level was detected.

Bioassays were performed on SASS train extract samples from the water injection test. The microbial mutagenesis assay showed negative mutagenicity. The cytotoxicity assay using WI-38 cells showed the sample to possess low toxicity.

Table 2-55. Flue Gas Composition (µg/dscm): T. H. Wharton Unit 52

	Baseline	Water Injection
NO_x	3.5×10^5	1.5×10^5
SO_2	3.1×10^4	3.4×10^4
$SO_3 + SO_4$	8.1×10^3	6.0×10^3*
CO	7.0×10^3	1.0×10^4
CO_2	8.0×10^7	8.4×10^7
Particulate	570	510
Antimony	<4.6	<4.7
Arsenic	<14	<14
Barium	<3.5	<3.6
Beryllium	<0.92	<0.14
Bismuth	<1.8	<2.3
Boron	$<2.2 \times 10^3$	$<2.0 \times 10^3$
Cadmium	<13	<0.55
Chromium	<17	<7.5
Cobalt	<0.55	<0.13
Copper	42	60
Iron	71	89
Lead	82	23
Manganese	<0.5	<0.05
Mercury	<2.8	<21
Molybdenum	<5.8	<4.8
Nickel	<0.2	<0.6
Selenium	<11	<10
Tellurium	<3.6	<3.4
Thallium	<11	<10
Tin	<16	<44
Titanium	<29	<33
Vanadium	<22	<49
Zinc	<760	800
Organics ($>C_7$)	1.3×10^3	1.1×10^3
Methane	1.6×10^3	2.4×10^3
Diphenyl ether	0.50	--
Diphenylcyclohexane	--	10
Fluoranthene	--	0.50
Naphthalene	--	1
Phenanthrene	0.50	1
Phenol	1.0	1
Pyrene	--	0.50
Terphenyl	--	5

*SO_4 sample destroyed

2.5.4 Residential Warm Air Furnace

One residential warm air furnace was tested in the NO_x EA: an oil-fired low emission Blueray System furnace (see Section 2.2.1.5). This unit was installed in a Medford, L.I., New York residence and had been in service for about one year. The test program encompassed testing under two modes of unit operation: continuous operation and cyclic (10 minutes on and 10 minutes off) operation. the cyclic mode is more representative of typical unit operation. Detailed test results are given in Reference 2-29. Test findings are summarized below.

Table 2-56 shows average flue gas concentration data for the two tests. In the cycling test, there were peaks in the CO and hydrocarbon emissions at the start and end of each period of operation. The peak at the start is included in the average concentration. Startup peak emissions averaged 2000 ppm for CO and 400 ppm for hydrocarbons. The NO_x levels started at 0 and, toward the end of the firing cycle, reached 16 ppm which was the average value for the continuous firing test. The average NO_x emissions were very low in both the cyclic and continuous operation tests. The startup effects do cause significantly higher CO and hydrocarbon emissions for the cyclic operation mode.

Particulate emissions were very low and no detectable difference was found due to changing from continuous operation to cyclic operation. Low particulate emission levels are expected with the efficient combustion by the Blueray burner and the low ash content of the fuel oil burned. Sulfur species determinations were inconclusive.

Table 2-57 shows the results of the Level 1 and the GC/MS organic analyses of the SASS flue gas organic extract sample. As the table shows, organic emissions increase substantially for cyclic operation and some POM species are found, though at very low levels. (The continuous test extract sample was not subjected to GC/MS analysis.) Liquid column chromatographic, infrared, and low resolution mass spectrometric analysis of the samples showed that, for both cyclic and continuous operation, the samples contained primarily aliphatic hydrocarbons, with some aromatics and carboxylic acids present.

Table 2-56. Flue Gas Composition: Blueray Unit

	Cyclic	Continuous
NO_x, ng/J as NO_2 ppm[a]	7.0 11	10 16
SO_2, ng/J	35.5	26.9
SO_3, ng/J	1.0	0.2
UHC, ng/J as CH_4 ppm, dry	5.0 23	0 0
CO, ppm dry	160	25
CO_2, % dry	12.9	13.1
O_2, % dry	4.0	3.8
Particulate, ng/J	1.30	1.32

Table 2-57. Organic Analysis Results ($\mu g/m^3$): Blueray Unit

	Cyclic	Continuous
Total C_7 organics	2.6×10^4	1300
Fluoranthene	0.026	--
Phenanthrene/Anthracene	0.77	--
Pyrene	0.009	--

Table 2-58 presents summary flue gas emission data, including those for trace element species. For comparison average Level 1 emission data from several conventional furnaces recently tested (Reference 2-30) are also shown. To facilitate direct comparisons, all concentration data in the table are shown as $\mu g/m^3$, calculated assuming an end of flue pipe (downstream of barometric damper) O_2 content of 17 percent, the average value found in the TRW tests.

Table 2-58. Flue Gas Composition (μg/dscm): Residential Warm Air Furnaces

	Blueray Cyclic	Blueray Continuous	Average Conventional Cyclic (Reference 2-30)
NO_x	5.4×10^3	7.7×10^3	4.2×10^4 [a]
SO_2	2.7×10^4	2.1×10^4	8.2×10^4 [a]
SO_3	770	150	4.5×10^3
CO	4.5×10^4	6.9×10^3	1.2×10^4 [a]
Antimony	<0.4	<0.4	4.4
Arsenic	<0.5	<0.46	1.2
Barium	<11	<8.5	12
Beryllium	<0.01	<0.012	--
Bismuth	<0.6	<0.62	--
Boron	<10	<3.0	--
Cadmium	<1.1	<1.7	8.5
Chromium	<5.5	<85	22
Cobalt	<5.7	<6.8	--
Copper	11	15	120
Iron	46	420	11
Lead	<21	<21	32
Manganese	<2.5	<12	--
Mercury	<3.0	<4.2	0.92
Molybdenum	<3.5	<11	--
Nickel	<11	68	220
Selenium	<1.8	<2.3	--
Tellurium	<0.8	<0.69	--
Thallium	<41	<37	--
Tin	<0.92	<0.69	--
Titanium	<1.0	<2.5	--
Vanadium	<1.1	<0.62	2.2
Zinc	2.8	3.2	85
Organics ($>C_7$)	6×10^3	290	2.4×10^3

[a] Calculated from AP-42 emission factors (Reference 2-31)

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SECTION 3

EVALUATION OF ENVIRONMENTAL EFFECTS

In this section the effects of the NO_x control methods tested in the NO_x EA program on combustion source potential environmental impact are summarized. Potential environmental impact for the source tested, under both baseline and controlled operation, is quantified using a source analysis model (SAM) developed for general use within all EPA Industrial Environmental Research Laboratory Environmental Assessment programs. The method used to evaluate the Level 1 data obtained was the rapid screening, SAM IA model.

Summary SAM IA results from the evaluation of the field test data presented in Section 2 are discussed in Section 3.1. Changes in total source potential hazard with the application of NO_x control are highlighted. In addition, bioassay results obtained in four of the field tests, as noted in Section 2, are compared and correlated with the SAM IA conclusions.

Section 3.2 goes on to highlight the effects of the NO_x controls tested on emissions of certain classes of highly toxic or carcinogenic species, based on the test data obtained. Section 3.3 summarizes program findings on the environmental impact of controls tested and gives overall conclusions concerning the environmental soundness of the controls tested.

It should be recalled in all the following discussions that the NO_x EA test program focused on current technology controls applied to priority conventional combustion sources under steady operation. Transient or upset conditions were not investigated, and advanced control concepts were not evaluated.

3.1 SOURCE ANALYSIS MODEL EVALUATIONS

The SAM IA model (Reference 3-1) was used to evaluate the field test data summarized in Section 2. SAM IA was designed for rapid screening purposes, and, as such, includes no treatment of pollutant transport or transformation. Comparisons are based on using effluent stream concentration goals, termed Discharge Multimedia Environmental Goals (DMEGs -- Reference 3-2).

The SAM IA model defines two indices of potential hazard. The first, termed Discharge Severity (DS), is the ratio of a discharge concentration to an appropriate DMEG. In these dimensionless evaluations the discharge concentration is those components for each MEG category detected in the Level 1 analysis of the effluent sample and the DMEG used is that for the most toxic species potentially present for the MEG category. A stream Total Discharge Severity (TDS) is also defined as the sum, over MEG categories (Level 1) of the DSs calculated for the discharge stream. The DS and TDS indices, thus, flag the existence of potential hazards.

The second SAM IA hazard index, termed Weighted Discharge Severity (WDS) is defined as the product of DS with the discharge stream mass flowrate. Stream total and source total WDSs are also defined. The WDS index, thus, is a measure of the magnitude of a potential hazard.

SAM IA evaluations were performed on each set of field test data reported in Section 2. Results for each combustion source category are reported, in turn, in the following sections.

3.1.1 Utility Boilers

Three utility boilers were tested in the NO_x EA program:

- A coal-fired tangential unit (Kingston Unit 6) with biased firing and burners out of service (BOOS) for NO_x control
- A coal-fired opposed wall unit (Crist Unit 7) with two BOOS patterns for NO_x control
- An oil-fired tangential unit (Moss Landing Unit 6) with flue gas recirculation through the windbox (FGR) and combined FGR and BOOS for NO_x control

Evaluation of test results by fuel are reported below.

3.1.1.1 Coal-Fired Utility Boilers

Kingston Unit 6

Table 3-1 shows results of the SAM IA evaluation of the inorganic flue gas composition from the tangential coal-fired utility boiler tests. Results are presented for uncontrolled operation (baseline), for a biased firing mode (Bias 1) and for a burners out of service mode (BOOS 2). The table shows discharge severity for each test for those components where DS

Table 3-1. Flue Gas Inorganic Discharge Severity: Kingston Unit 6

Component	Discharge Severity		
	Baseline	Bias 1	BOOS 2
SO_2	320	270	320
NO_x	130	82	73
Fe	64	47	47
As	48	39	41
CO_2	30	31	32
$SO_4^=$ (condensed)	24	12	29
SO_3 (vapor)	12	11	12
Be	4.5	5.5	3.6
Ba	4.5	3.4	3.0
Ca	1.4	1.7	1.6
Co	1.3	1.5	1.8
Ti	1.0	0.95	0.60
CO	0.77	1.1	0.80
Cl	0.68	1.0	2.1
Total stream	640	510	570

was greater than 1 in any test, ordered by DS for the baseline test. Discharge severities shown are based on air/health DMEGs. Tables 3-2 through 3-4 show corresponding tables for the bottom ash mechanical collector hopper ash, and the ESP hopper ash respectively. DS values in these tables were calculated using land/health based DMEGs.

The results presented in Table 3-1 show that the flue gas species SO_2 and NO_x present the greatest potential hazard from this source. In fact, the sum of the DSs for these two species represents about 70 percent of the stream TDS for each firing mode. Thus, when NO_x control is applied, the NO_x DS decreases appropriately (of the order of 35 to 45 percent) and stream TDS is decreased, although changes in the SO_2 DS, due solely to changes in fuel sulfur content, tend to overshadow some of the NO_x control effects.

Other flue gas species of concern include CO_2, SO_3 (vapor phase H_2SO_4), CO, condensed (particulate) sulfate, and several trace elements. By and large the DS values for these remain relatively constant with firing mode.

Tables 3-2 through 3-4 show that for the ash streams, discharges of Mn, Cr, Ba, Be, and Ni present potential environmental hazard for all streams. In addition, As, S, and Pb have DS greater than 1 in the ESP hopper ash stream.

The WDS index is the appropriate one for comparing the magnitude of potential hazard and for evaluating total source potential hazard presented among different streams. Thus, Table 3-5 shows the stream total WDS for each effluent stream from the utility boiler. The values in the table show that the flue gas stream dominates the total source WDS, being two orders of magnitude larger than the WDS for any ash stream. Thus, when NO_x control is applied, flue gas WDS decreases, ash stream WDS remains relatively constant, and total source WDS decreases. This suggests that the NO_x controls tested in this program are environmentally beneficial: they reduce total stream potential hazard.

Crist Unit 7

Table 3-6 shows the results of the SAM IA evaluation of the flue gas composition from the opposed wall coal-fired utility boiler tests. Results are presented for uncontrolled operation (baseline) and for the two modes of NO_x control by burners out of service tested (BOOS 1 and

Table 3-2. Bottom Ash Inorganic Discharge Severity: Kingston Unit 6

Component	Discharge Severity		
	Baseline	Bias 1	BOOS 2
Mn	5.6	4.0	3.4
Cr	3.2	3.4	3.2
Ba	2.4	2.0	2.6
Be	1.7	1.7	1.7
Ni	1.4	2.4	1.3
Total stream	18	17	16

Table 3-3. Mechanical Collector Hopper Ash Inorganic Discharge Severity: Kingston Unit 6

Component	Discharge Severity		
	Baseline	Bias 1	BOOS 2
Mn	3.8	2.6	2.8
Cr	3.4	3.2	3.8
Ba	3.0	2.4	2.9
Be	1.7	1.7	2.0
Ni	1.4	1.2	1.6
Total stream	18	16	18

Table 3-4. ESP Hopper Ash Inorganic Discharge Severity: Kingston Unit 6

Component	Discharge Severity		
	Baseline	Bias 1	BOOS 2
Mn	4.0	3.2	3.2
Cr	3.6	3.8	4.0
Ba	2.8	3.2	2.9
As	2.6	2.0	2.4
Be	2.0	2.3	2.2
Ni	2.0	2.2	2.2
S	1.7	1.5	1.4
Pb	1.2	1.5	1.4
Total stream	23	23	23

Table 3-5. Weighted Discharge Severity: Kingston Unit 6

Stream	Weighted Discharge Severity (kg/s)		
	Baseline	Bias 1	BOOS 2
Flue gas	4.5×10^4	3.5×10^4	3.9×10^4
Bottom ash	57	53	42
ESP Hopper Ash	6.1	6.1	5.1
Mechanical hopper	19	16	16
Total source	4.5×10^4	3.5×10^4	3.9×10^4

Table 3-6. Flue Gas Discharge Severity: Crist Unit 7

Component	Discharge Severity		
	Baseline	BOOS 1	BOOS 2
SO_2	477	500	481
NO_x	109	66	92
As	26	27	25
SO_4 (condensed)	26	16	26
Fe	23	150	29
SO_3 (vapor)	21	7.2	12
CO_2	19	17	28
CO	7.3	11	9.8
Be	7.0	5.0	5.5
Ba	5.2	2.0	4.6
Ti	4.3	2.9	3.7
Carboxylic acids	4.3	0.72	2.1
Co	3.4	2.2	2.8
Total stream	737	811	721

BOOS 2). The table shows DS for each test for those components with DS greater than 1 in any test. DS values shown were calculated based on air/health DMEGs. Tables 3-7 and 3-8 show corresponding results for the bottom ash and ESP hopper ash streams respectively. DS values in these tables were calculated using land/health based DMEGs.

The results presented in Table 3-6 show that, as was the case for the Kingston Unit 6 evaluation, the flue gas species NO_x and SO_2 again present the greatest potential hazard. Here the sum of the DS for these two species average about 75 percent of the stream TDS for each test. Again the NO_x DS decreases with NO_x control application, but here stream TDS remains relatively constant because of fluctuations in the SO_2 DS. These fluctuations are due to changes in fuel sulfur content, thus suggesting that any possible adverse environmental effects of NO_x control are at least of lesser magnitude than those deriving from day to day variations in coal sulfur content. The DS of iron also plays an important part in determining stream TDS. The TDS for the BOOS 1 test, especially, is high because of the iron contribution, probably anomalous.

Other flue gas species of concern from Crist Unit 7 include CO_2, SO_3 (vapor), $SO_4^=$ (condensed), CO, and several trace element species. In fact the trace elements flagged in Table 3-6 are largely the same as those flagged in Table 3-1 (As, Fe, Be, Ba, and CO appear in both tables with comparable DS). Interestingly, the SO_3 DS apparently decreases with NO_x control application, suggesting that perhaps less SO_2 is oxidized to SO_3 in the more reducing conditions attendant with staged firing. This needs more investigation, however, since the trend was not observed in the Kingston test.

The SAM IA evaluation of Crist Unit 7 flue gas also flags an organic category with potential DS greater than 1, carboxylic acids. This arises because, as noted in Section 2.2.1, infrared analysis of flue gas organic extracts noted the possible presence of aliphatic hydrocarbons, ethers, and carboxylic acids. In these MEG categories, the compound with the lowest DMEG is maleic acid. Thus a DS value for each firing mode was calculated under the conservative assumption that all the organic material determined in the flue gas was maleic acid. Even under this assumption, the highest possible DS for each test was low.

Tables 3-7 and 3-8 show that for the ash streams, discharges of Fe, Mn, Cr, Be, Ti and Ni present potential environmental hazard for both ash streams. All these except for Fe and Ti were also flagged from the Kingston tests. In addition, Pb and Ba have DS greater than 1 for the ESP hopper ash. Interestingly, for both the Kingston and the Crist data, Pb has DS greater than 1 only for the ESP hopper ash, which suggests that lead is being concentrated in the ash to potentially hazardous levels on passing through the boiler.

In the Crist results, the DS for iron dominates ash stream TDS, and fluctuations in its concentration cause corresponding large fluctuations in stream TDS. The DS values for the other trace elements flagged remain relatively constant with firing mode.

Table 3-9 shows the stream total WDS for each effluent stream from the utility boiler. Again, the flue gas WDS dominates the total source WDS, being about three orders of magnitude larger than the WDS for any ash stream. Thus changes in total source potential hazard will reflect changes in flue gas TDS as discussed above. Following from that discussion, it can be concluded that application of the NO_x controls tested at least do not, of themselves, increase source potential hazard.

3.1.1.2 Oil-Fired Utility Boiler

Table 3-10 shows results of the SAM IA evaluation of the flue gas composition data from the residual oil-fired utility boiler tested. Results are presented for uncontrolled operation (baseline) and for two levels of NO_x control: flue gas recirculation through the windbox (FGR) and combined FGR and burners out of service (FGR + BOOS). The table shows MEG category DS, based on air/health DMEGs, for each test for those components with DS greater than 1 in any test. Stream total discharge severities and weighted discharge severities are also listed. Since the flue gas is the only discharge stream from the unit, the stream total WDS is also the source total WDS.

The table shows that the flue gas species, NO_x, CO_2, SO_2, and vapor phase SO_3 (sulfuric acid) rank high among the pollutants of concern. Particulate sulfate and several trace elements are also flagged as having potential adverse impact. The only organic category flagged with possible DS greater than 1 is carboxylic acids and derivatives. It was flagged following the assumption outlined above for the Crist evaluation.

Table 3-7. Bottom Ash Discharge Severity: Crist Unit 7

Component	Discharge Severity		
	Baseline	BOOS 1	BOOS 2
Fe	137	633	143
Mn	18	22	19
Cr	1.5	2.0	1.5
Be	1.5	1.1	1.3
Ti	1.3	1.3	1.3
Ni	1.2	1.1	1.2
Total stream	163	664	170

Table 3-8. ESP Hopper Ash Discharge Severity: Crist Unit 7

Component	Discharge Severity		
	Baseline	BOOS 1	BOOS 2
Fe	110	533	93
Mn	24	24	12
Ni	3.3	1.0	2.0
Cr	2.6	2.4	2.2
Ti	1.3	1.3	1.3
Pb	1.2	1.2	1.4
Be	1.2	1.5	1.1
Ba	0.19	1.2	0.059
Total stream	146	569	115

Table 3-9. Weighted Discharge Severity: Crist Unit 7

Stream	Weighted Discharge Severity (kg/s)		
	Baseline	BOOS 1	BOOS 2
Flue gas	4.5×10^5	6.6×10^5	5.1×10^5
Bottom ash	340	930	370
ESP hopper ash	740	2200	480
Total source	4.5×10^5	6.6×10^5	5.1×10^5

Table 3-10. Flue Gas Discharge Severity: Moss Landing Unit 6

Component	Discharge Severity		
	Baseline	FGR	FGR + BOOS
NO_x	64	49	37
SO_2	32	35	32
CO_2	27	29	26
$SO_4^=$ (condensed)	11	12	8.0
SO_3 (vapor)	6.6	6.8	9.3
Carboxylic acids	4.4	1.4	1.4
As	4.3	4.2	3.8
CO	2.0	0.30	1.4
B	1.7	8.4	0.77
Co	1.2	1.1	0.74
V	1.0	0.98	0.68
Cu	0.30	7.5	3.0
Total stream DS	160	157	127
Total Source WDS (Mg/s)	110	110	83.5

The table also shows that the stream TDS generally decreases with progressive application of NO_x control. The DS for NO_x decreases progressively, while the DS values for the other components remain largely unchanged. Here, the fraction of sulfur emitted as SO_3 and sulfate remains essentially constant. Again, this suggests that control of NO_x in this unit by FGR and BOOS, is environmentally sound. The up to 40 percent reduction in NO_x is not offset by any substantial increase in other pollutant potential hazard.

3.1.2 Industrial Boilers

Two coal-fired stoker industrial boilers were tested in the NO_x EA. Results of the SAM IA evaluation of the test data obtained are discussed in the following.

Stoker Site A

Table 3-11 shows the results of the SAM IA evaluation of the flue gas composition data from Site A. Results are presented for uncontrolled operation (baseline) and controlled operation (low NO_x via low excess air and overfire air). The table shows DS for each firing condition for those components with DS greater than 1 in either test. DS values shown were calculated from air/health based DMEGs. Tables 3-12 through 3-14 show corresponding results for the bottom ash, mechanical collector hopper ash and the ESP hopper ash respectively. DS values in these tables are based on land/health DMEGs.

The results presented in Table 3-11 show again that NO_x and SO_2 are the potentially most hazardous flue species. The sum of the DS values for these two species again comprises over 70 percent of the stream TDS. The DS for SO_2 again fluctuates with day to day fuel sulfur content, masking the effects of the reduction of the NO_x DS with the application of NO_x control, so that stream TDS remains relatively constant with NO_x control application. Other species of potential concern include CO, SO_3 (vapor), and several trace elements. In this test, though, the SO_3 DS did not decrease with NO_x control and in fact increased six-fold. However, this increase may be within the accuracy of the analytical technique used to measure SO_3. Carboxylic acids are flagged here also, under the same conservative assumptions employed in evaluating the utility boiler test results.

Table 3-11. Flue Gas Discharge Severity: Site A

Component	Discharge Severity	
	Baseline	Low NO_x
NO_x	70	58
SO_2	63	85
CO	6.3	12
SO_3 (vapor)	5.8	35
Be	1.9	0.049
As	1.6	3.5
Fe	1.1	1.9
Carboxylic acids	1.0	1.8
Ti	0.34	3.7
Cd	0.61	1.7
Pb	0.38	1.2
Total stream	154	206

Table 3-12. Bottom Ash Discharge Severity: Site A

Component	Discharge Severity	
	Baseline	Low NO_x
Fe	100	100
Mn	11	11
Sn	1.7	1.3
Total stream	115	118

Table 3-13. Mechanical Collector Hopper Ash Discharge Severity: Site A

Component	Discharge Severity	
	Baseline	Low NO_x
Fe	11	22
Mn	1.4	3.0
Total stream	14.1	27.6

Table 3-14. ESP Hopper Ash Discharge Severity: Site A

Component	Discharge Severity	
	Baseline	Low NO_x
Fe	87	80
Mn	11	10
Pb	2.2	2.4
Ni	1.2	1.1
Total stream	105	98

Tables 3-12 through 3-14 indicate that, for the ash streams, discharges of Fe and Mn represent the greatest potential hazard. Still the DS values for these remain relatively constant with firing mode. Both of these elements were also flagged in the ash streams from the coal-fired utility boilers evaluated. Also, as was the case in the coal-fired utility boiler tests, Pb is flagged of concern in the ESP hopper ash only, again suggesting that it becomes concentrated to potentially hazardous levels on passage through the unit.

Table 3-15 shows stream total WDS for each stream under each firing mode tested. As was the case for the coal-fired utility boiler, the flue gas stream dominates the potential hazard of the source, with a WDS over two orders of magnitude larger than any other stream. In addition, the WDSs for the ash streams remain relatively constant with firing mode. Thus, changes in flue gas WDS will elicit corresponding changes in total source WDS. So again, it is concluded that the NO_x control tested does not, of itself, increase total source potential hazard.

Stoker Site B

Table 3-16 shows the results of the SAM IA evaluation of the flue gas from the Site B unit. Results for the two modes of operation (baseline and low NO_x via low excess air) are presented. DS values for those compounds with DS greater than 1 in either test are displayed. These values were calculated based on air/health DMEGs. Tables 3-17 through 3-19 show corresponding results for the ash streams evaluated, with DS values here based on land/health DMEGs.

Conclusions drawn from the results presented in Table 3-16 are analogous to those discussed above on the results in Table 3-11. NO_x and SO_2 remain the potentially most hazardous species, accounting for over half the flue gas of stream TDS. Here, though, the DS for SO_2 (which varies exclusively with fuel sulfur content) drops in the low NO_x mode, so that stream TDS decreases with NO_x control application.

Other flue gas species with DS greater than 1 include CO_2, CO, SO_3 (vapor) and the trace elements As and B. The DS for SO_3 shows essentially no change with firing mode. In addition, for this test no organic category had a DS value greater than 1.

Table 3-15. Weighted Discharge Severity: Stoker Site A

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	6600	7900
Bottom ash	15	16
Mechanical collector hopper ash	1.7	1.8
ESP hopper ash	5.3	2.6
Total source	6610	7890

Table 3-16. Flue Gas Discharge Severity: Stoker Site B

Component	Discharge Severity	
	Baseline	Low NO_x
NO_x	68	38
SO_2	41	23
CO_2	35	27
As	18	20
B	2.2	2.5
SO_3 (vapor)	2.4	2.2
CO	1.4	0.88
Total stream	168	114

Table 3-17. Bottom Ash Discharge Severity: Stoker Site B

Component	Discharge Severity	
	Baseline	Low NO_x
Fe	--[a]	67
Mn	--	9.2
Cr	--	2.2
Ni	--	1.1
Total stream	--	82.1

[a] Bottom ash sample not taken for baseline test

Table 3-18. Mechanical Collector Hopper Ash Discharge Severity: Stoker Site B

Component	Discharge Severity	
	Baseline	Low NO_x
Cr	180	1.3
Fe	47	27
Pb	8.4	0.14
Mn	6.2	5.0
Be	4.0	0.83
Total stream	249	36.3

Table 3-19. ESP Hopper Ash Discharge Severity:
Stoker Site B

Component	Discharge Severity	
	Baseline	Low NO_x
As	15	12
Be	13	12
Se	8.4	12
Ba	4.4	2.8
$SO_4^=$ (condensed)	3.7	77
Total stream	45	117

Tables 3-17 and 3-18 indicate that discharges of Fe, Mn, Cr, Be, and Ni are the potentially hazardous ones for the bottom and mechanical collector hopper ash streams from this source as well. (No bottom ash sample was taken in the Site B baseline test, so no comparisons with firing mode are possible here.) Interestingly, some new species not flagged previously: coal-fired source ash streams, Se and condensed sulfate, appear in Table 3-19.

Table 3-20 shows stream total WDS values for each stream under both firing modes tested. Previously stated conclusions hold here as well. The flue gas stream dominates potential source hazard. The application of NO_x control reduces the hazard presented by NO_x. DS changes caused by day to day fuel composition changes are often of greater magnitude than the reduction in NO_x DS. Thus, NO_x control application reduces total source potential hazard in the absence of SO_2 considerations.

3.1.3 Gas Turbines

In the NO_x EA a 60 MW oil-fired utility gas turbine with water injection for NO_x control, T.H. Wharton Unit 52, was tested. Table 3-21 summarizes results of the SAM IA evaluation of the test data obtained. The table lists DS values for the exhaust gas stream under both uncontrolled (baseline) and controlled (water injection) operation for

Table 3-20. Weighted Discharge Severity: Stoker Site B

Stream	Weighted Discharge Severity (kg/s)	
	Baseline	Low NO_x
Flue gas	7160	3640
Bottom ash	--[a]	7.7
Mechanical collector hopper ash	50	5.5
ESP hopper ash	1.9	3.7
Total source	7210	3660

[a] Bottom ash sample not taken for baseline test.

Table 3-21. Flue Gas Discharge Severity:
T. H. Wharton Unit 52

Component	Discharge Severity	
	Baseline	Low NO_x
NO_x	39	17
Cr	17	8
CO_2	8.9	9.3
SO_3 (vapor)	8.1	6.0
As	7.0	7.0
SO_2	2.4	2.6
Cd	1.3	0.055
Total stream	87.0	52.2
Total stream WDS (mg/s)	21.7	12.6

those species where the DS value exceeded 1 in either test. The DS values shown were calculated using health based air DMEGs.

The table shows that only inorganic species were emitted from the unit at levels exceeding DMEG values. The potentially most hazardous organic category emitted was carboxylic acids with maximum DS of 0.6 and 0.5 for baseline and water injection operation respectively. Of the inorganic species, NO_x presents the greatest potential hazard. The oxides of sulfur, SO_2 and SO_3 (vapor phase sulfuric acid); CO_2; and the trace metals As, Cd, and Cr also have DS greater than 1.

With water injection for NO_x control, the DS for NO_x is about halved, while those for the other species remain generally unchanged. Thus, total stream DS is decreased with wet NO_x control. Moreover, since the exhaust gas stream is the only discharge stream from this source, the WDS for the turbine also decreases with wet NO_x control. The conclusion that water injection for NO_x control in gas turbines represents an environmentally sound technique seems warranted.

3.1.4 Residential Warm Air Furnace

An oil-fired residential warm air furnace (the Blueray System) was tested in the NO_x EA program. As noted in Section 2, tests under cyclic, as well as continuous operation were performed. Data from these tests can be compared to results obtained in a separate test program performed on conventional residential warm air furnaces (Reference 3-3).

Results of the SAM IA evaluation of flue gas composition for the Blueray furnace under both cyclic (10 minutes on, 10 minutes off) and continuous operation and the "average" conventional furnace under cyclic operation (50 minutes on, 10 minutes off), (Reference 3-3) are shown in Table 3-22.

The table shows health based discharge severities for those components with DS exceeding 1 for any test. Discharge severities for NO_x, SO_2, and CO for the conventional furnace were calculated using AP-42 emission factors (Reference 3-4) as these species were not directly measured in this furnace test program.

The table indicates that, for both types of unit, Cr and Ni emissions appear to present the greatest potential environmental hazard; in all cases their DS is a sizable fraction of total stream DS.

Table 3-22. Flue Gas Discharge Severity: Oil-Fired Residential Warm Air Furnaces

Component	Conventional Cyclic	Discharge Severity Blueray Continuous	 Blueray Cyclic
Cr[b]	22	85	5.5
Ni[b]	15	4.5	0.73
Alkylhalides	13	--	--
SO_2	6.3[a]	1.6	2.1
NO_x	4.7[a]	0.86	0.60
SO_3	4.5	0.15	0.77
Amines	1.6	--	--
Carboxylic acids	--	0.90	10
Benzene and substituted benzene	--	--	1.2
Phenols	--	--	1.2
CO	0.30[a]	0.17	1.1
Total stream	69.7	94.8	24.5
Total stream WDS (kg/s)	--	865	223

[a] Species not measured during tests; DS, based on AP-42 emission factor (Reference 3-4)

[b] Possible artifact of sampling train

However, measured levels of these metals may be an artifact of the stream sampling methodology. The flue gas sampling trains in both the conventional furnace test program and the NO_x EA contained many stainless steel components. Thus, some of the reported Cr and Ni could have come from the sampling train itself rather than being a significant component of the flue gas.

For both types of units SO_2 emissions were flagged and emissions of certain organic categories had DS values greater than 1. For the conventional units amines were flagged as being of potential concern; for the Blueray unit carboxylic acids, aromatics, and phenols would be of potential concern under cyclic operation. The DS for NO_x exceeds 1 for conventional units, but is less than 1 for the low NO_x Blueray unit under both continuous and cyclic operations.

In summary, flue gas stream Total Discharge Severity (TDS) for typical conventional units appears to fall between the TDS for the low NO_x unit under cyclic (normal) operation and that for the low NO_x unit under continuous operation. If Cr and Ni are removed from the TDS calculations, adjusted TDSs of 32.7, 5.3, and 18.3 result for the conventional, Blueray continuous, and Blueray cyclic data respectively. Thus, if measured Cr and Ni indeed comes from the sampling train, then the low NO_x unit's TDS under both cyclic and continuous operation is lower than that of the conventional units. This suggests that using the Blueray design to control NO_x from oil-fired heating units is environmentally sound.

3.1.5 Bioassay Results

Bioassay testing of samples taken during the Crist Unit 7, Moss Landing Unit 6, Site B and gas turbine lowest NO_x tests was performed in the test program. Specific results are discussed in Section 2. Additionally, it is also of interest to compare these results to the SAM IA evaluation conclusions discussed above. Thus, Table 3-23 summarizes results from all the bioassay tests performed and notes the stream TDS for the appropriate sample assayed. However, from the data presented in the table no real correlation between stream TDS and bioassay test results is apparent. The fact that most bioassays gave nondetectable toxicity responses frustrates deriving any correlation.

Table 3-23. Bioassay/Discharge Severity Comparison

Test/Sample	Bioassay Result[a]						
	Stream TDS	Microbial Mutagenesis	Cytotoxicity		Rodent Acute Toxicity	Freshwater Algae	Freshwater Fish
			RAM	WI-38			
Crist Unit 7							
>3 μm flyash	830[b]	Neg.	ND	--	--	--	--
<3 μm flyash		Neg.	L	--	--	--	--
Bottom ash	170	Neg.	ND	--	ND	ND	ND
ESP hopper ash	115	Neg.	ND	--	ND	ND	ND
Moss Landing Unit 6							
XAD-2 extract	84[b]	Neg.	--	M	--	--	--
Site B							
Bottom ash	82	Neg.	ND	--	ND	ND	ND
ESP hopper ash	117	Neg.	L	--	ND	--	--
Gas Turbine							
XAD-2 extract	13[b]	Neg.	--	L	--	--	--

[a] Neg: Negative, ND: Not detectable; L: Low toxicity; M: Medium toxicity (Reference 3-5)

[b] Total flue gas TDS cited

3.1.6 Summary of SAM IA Results

Tables 3-24 and 3-25 present a summary of the SAM IA results presented in this section with respect to noting the pollutants of concern flagged by the analysis as presenting potential for adverse environmental impact. The tables show pollutant components with DS values greater than 1 for any source tested, with an indication of the magnitude of the DS for each component for each source. Table 3-24 presents results for the flue gas stream; Table 3-25 for the ash streams.

From Table 3-24 it is apparent that, as noted in each of the preceding subsections, SO_2 and NO_x emissions present the greatest potential hazard from all the combustion sources tested. The DS for these is especially high from coal-fired sources. Other species with high DS in most tests include CO_2, CO, As, and SO_3 (vapor phase). The only organic emissions of potential concern noted were those of carboxylic acids; though this would be so only under the very conservative assumption that all the organics analyzed in SASS train catches consisted of the most toxic carboxylic acid on the MEG list: maleic acid. Even so, the DSs calculated are only of order 1. Several other trace element species and condensed sulfate were flagged of concern in several tests, though these were not universally noted.

Table 3-25 shows that the potentially most hazardous species in the ash streams from coal-fired sources were iron and manganese, followed by chromium, nickel, beryllium, and barium. Interestingly, lead levels were high only in particle collector ash streams, particularly the ESP hopper ash, suggesting that it partitions to potentially hazardous levels on passage through a boiler.

General conclusions that can be derived from the SAM IA evaluations include:

- NO_x and SO_2 represent the potentially most hazardous flue gas species from the sources tested; the sum of the DS values for these two species in general accounts for greater than half the stream TDS
- The flue gas stream WDS dominates the source total WDS for sources which discharge other (ash) streams (coal-fired sources)

Table 3-24. SAM I Summary for Flue Gas

Component	DS Level[a]						
	Kingston Unit 6	Crist Unit 7	Moss Landing Unit 6	Site A	Site B	T.H. Wharton Unit 52	Blueray Furnace
SO_2	+++	+++	++	++	++	+	+
NO_x	+++	+++	++	++	++	+	-
CO_2	++	++	++	-	++	+	-
As	++	++	+	+	++	+	-
SO_3 (vapor)	++	++	+	++	+	+	-
CO	+	++	+	+	+	-	+
$SO_4^=$ (condensed)	++	++	++	-	-	-	-
Fe	++	++	-	+	-	-	-
Carboxylic acids	-	+	+	+	-	-	+
Be	+	+	-	+	-	-	-
Co	+	+	+	-	-	-	-
Ba	+	+	-	-	-	-	-
B	-	-	+	+	-	-	-
Ti	-	+	-	+	-	-	-
Cu	+	-	+	-	-	-	-
Cd	-	-	-	+	-	+	-
Pb	-	-	-	+	-	-	-
Cl	+	-	-	-	-	-	-
U	-	-	+	-	-	-	-

[a]Key: +++ denotes DS ≥100
++ denotes DS ≥10
+ denotes DS ≥1
- denotes DS <1 or species not measured

Table 3-25. SAM IA Summary for Ash Streams

Ash Stream	Component	DS Level[a]			
		Kingston Unit 6	Crist Unit 7	Stoker Site A	Stoker Site B
Bottom ash	Fe	-	+++	+++	++
	Mn	+	++	++	++
	Cr	+	+	-	+
	Ni	+	+	-	+
	Be	+	+	-	-
	Ba	+	-	-	-
	Ti	-	+	-	-
	Sn	-	-	+	-
Mechanical collector hopper ash	Fe	-	-[b]	++	++
	Mn	+	-	+	+
	Be	+	-	-	+
	Cr	+	-	-	+
	Ba	+	-	-	-
	Pb	-	-	-	+
	Ni	+	-	-	-
ESP hopper ash	Fe	-	+++	++	-
	Mn	+	++	++	-
	Be	+	+	-	++
	Ba	+	+	-	+
	Pb	+	+	+	-
	As	+	-	-	++
	Ni	+	+	+	-
$SO_4^=$	Cr	+	+	-	-
	SO_4	+	-	-	+
	Se	-	-	-	++
	Ti	-	+	-	-

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[a] Key: +++ denotes DS ≥100
++ denotes DS ≥10
+ denotes DS ≥1
- denotes DS <1 or species not measured

[b] No mechanical collector at Crist Unit 7

- NO_x control application either reduces flue gas TDS and WDS, or, at worst, does not increase these; this translates to a reduction, or, at worst, no increase in source total WDS
- In general, changes in flue gas TDS and WDS due to NO_x control are less significant than those resulting from day to day variations in fuel composition (especially sulfur).

3.2 INCREMENTAL EFFECTS OF COMBUSTION MODIFICATION CONTROLS

In the preliminary environmental assessment performed during the first year of the NO_x EA (Reference 3-6), it was concluded that further study was needed on the effects of NO_x controls on emissions of:

- CO and vapor phase hydrocarbons
- Particulate and particulate size distribution
- Trace elements and trace element partitioning
- SO_3 and condensed sulfates
- POM and other condensed organic species.

The test program performed as described in Section 2 addressed these concerns for the current technology combustion modification controls applied to the priority combustion sources under steady operation. A summary of the results obtained in the test program with respect to effects of the controls tested on emissions of these species is given in the following subsections.

3.2.1 Carbon Monoxide and Vapor Phase Hydrocarbons

The presence of CO and vapor phase hydrocarbons (HC) in the exhaust gases of combustion systems results from incomplete fuel combustion. The various combustion modification controls tested can give rise to conditions resulting in incomplete combustion, so increased emissions of CO and HC can be a concern in NO_x control application. However, since emissions of CO and HC are associated with decreased efficiency, combustion sources are generally operated, even with NO_x control, to keep these emissions at a minimum. Indeed, the preliminary environmental assessment (Reference 3-6) concluded that increased emissions of these emissions due to combustion modification control should not be considered a major concern. Results of the NO_x EA test program substantiate this conclusion.

Table 3-26 shows CO and HC emissions as a function of NO_x control application for the tests performed. As noted in the table, emissions of these either remain relatively unchanged or increase only slightly with the combustion modifications tested.

3.2.2 Particulate and Particle Size Distribution

The preliminary environmental assessment (Reference 3-6) concluded that the effects of combustion modification controls on particulate emissions, and especially on emitted particle size distribution, from stationary sources had been insufficiently studied. Further, since NO_x controls can produce combustion conditions conducive to increasing particulate emissions, this was flagged as an area of potential concern.

The data obtained in the NO_x EA test program on particulate emissions are summarized in Table 3-27. The table shows that particulate mass emissions generally remain unaffected, or are decreased slightly with the NO_x control applications tested. Particle size distribution data taken for the coal-fired sources also showed that emitted particle size distribution remained unaffected or increased slightly (References 3-7 through 3-10).

3.2.3 Trace Element Emissions

The preliminary environmental assessment (Reference 3-6) concluded that the effects of NO_x control application on emissions of trace elements, both segregating (those which tend to partition to fine particulate) and nonsegregating (those which tend to remain equally distributed with particle size in ash), should be marginal. However, the preliminary assessment noted that few data existed to substantiate that conclusion.

The data obtained in the NO_x EA test program, however, do indicate that combustion modification controls have no measurable effect on trace element emissions. All the data presented in the tables in Section 3.1 show that, within analytical uncertainties, trace element levels in flyash, bottom ash, and particulate collector hopper ash streams remain generally unchanged as a function of NO_x control application.

In addition, data presented in References 3-7 through 3-10 also indicate that:

- Trace element partitioning to fine particulate occurs in accordance with expectations (Reference 3-6), but

Table 3-26. Effects of Controls Tested on CO and HC Emissions

Test	Fuel	Control[a]	CO Emissions (ppm[b])			HC Emissions (ppm[b])		
			Baseline	Intermediate NO_x	Low NO_x	Baseline	Intermediate NO_x	Low NO_x
Kingston Unit 6	Coal	Bias, BOOS	29	35	22	0	C	0
Crist Unit 7	Coal	BOOS	357	392	608	6.3	19.0	6.3
Moss Landing Unit 6	Residual and crude oil	FGR, BOOS/FGR	69	10	49	0	0	0.05
Stoker Site A	Coal	OFA	243	-	483	97	-	c
Stoker Site B	Coal	LEA	65	-	36	23	-	103
T.H. Wharton Unit 52	Distillate oil	WI	5.6[d]	-	8.1[d]	2.3[e]	-	3.5[e]
Blueray Furnace	Distillate oil	New design	-	-	160	-	-	23

[a] Bias: Biased burner firing; BOOS: Burners out of service; FGR: Flue gas recirculation; OFA: High overfire air; LEA: Low excess air; WI: Water injection

[b] 3 percent O_2, dry

[c] Data not available

[d] 15 percent O_2, dry

[e] Wet

Table 3-27. Effects of Controls Tested on Particulate Emissions

Test	Fuel	Control[a]	Particulate Emissions (ng/J)		
			Baseline	Intermediate NO_x	Low NO_x
Kingston Unit 6	Coal	Bias, BOOS	228	238	160
Crist Unit 7	Coal	BOOS	460	340	360
Moss Landing Unit 6	Residual and crude oil	FGR, BOOS/FGR	23	22	16
Stoker Site A	Coal	OFA	13	-	24
Stoker Site B	Coal	LEA	8.0	-	10.0
T.H. Wharton Unit 52	Distillate oil	WI	19	-	16
Blueray Furnace	Distillate oil	New design	-	-	1.3

[a] Bias: Biased burner firing; BOOS: Burners out of service; FGR: Flue gas recirculation; OFA: High overfire air; LEA: Low excess air; WI: Water injection

- Changes in trace element partitioning tendencies with combustion modifications are undetectable

3.2.4 SO_3 and Sulfate Emissions

High ambient sulfate levels are currently a matter of great concern in regions of the U.S. with large numbers of combustion sources firing sulfur bearing coal and oil. The primary reason for this concern is that increasing ambient sulfate levels are contributing to the problem of acid rain, particularly in the northeast U.S., but in other parts of the country as well. Ambient sulfates are comprised of directly emitted, or primary, sulfates and those derived from the atmospheric oxidation of SO_2, or secondary sulfates. Although the relative contributions to ambient sulfate levels from each of these is undetermined, it is clear that an increase in primary sulfate emissions should be viewed with concern.

Combustion modification NO_x control would be expected to either reduce or leave unchanged the emissions of primary sulfates from combustion sources. Such was the conclusion of the preliminary environmental assessment (Reference 3-6). However, the preliminary assessment also noted that few data to substantiate this conclusion existed, thus obtaining such data was given priority.

Table 3-28 shows the flue gas SO_3 and particulate sulfate data taken during the test program. Also shown is the weight fraction of sulfur emitted as SO_3 and $SO_4^=$, expressed as the ratio $(SO_3 + SO_4^=)(SO_2 + SO_3 + SO_4^=)$. The table shows that the fraction of sulfur emitted as SO_3 and particulate sulfate varies from just under 1 percent for coal-fired sources to 5 to 10 percent for oil-fired sources, in agreement with previous data (Reference 3-11). The table also shows that the fraction of sulfur emitted as $SO_3 + SO_4^=$ remains relatively constant, or decreases slightly with NO_x control application.

3.2.5 Polycyclic Organic Matter and Other Organic Emissions

Just as combustion modification controls have the potential for increasing CO and HC emissions due to decreased combustion efficiency, emissions of other organic species can potentially increase also. Since few data existed on the effects of NO_x controls on combustion source POM and other organic emissions, and since several species in this pollutant

Table 3-28. Effects of Controls Tested on Flue Gas SO_3 and $SO_4^=$ Emissions

Test	Fuel	Control[a]	SO_3 Emissions (ng/J)			$SO_4^=$ Emissions (ng/J)			$\frac{SO_3 + SO_4^=}{SO_2 + SO_3 + SO_4^=}$ (%)		
			Baseline	Intermediate NO_x	Low NO_x	Baseline	Intermediate NO_x	Low NO_x	Baseline	Intermediate NO_x	Low NO_x
Kingston Unit 6	Coal	Bias, BOOS	4.3	3.9	4.5	8.6	4.4	11.0	0.85	1.24	0.98
Crist Unit 7	Coal	BOOS	9.5	4.5	3.6	11.6	9.6	8.2	0.75	0.50	0.36
Moss Landing Unit 6	Residual and crude oil	FGR,BOOS/FGR	0.96	0.96	1.3	1.6	1.6	1.3	4.1	4.0	3.9
Stoker Site A	Coal	OFA	2.2	--	12.0	b	--	b	0.70[c]	--	3.0[c]
Stoker Site B	Coal	LEA	0.8	--	0.5	b	--	b	0.46[c]	--	0.46[c]
T.H. Wharton Unit 52	Distillate oil	WI	3.0	--	5.0	4.0	--	b	9.4	--	14.3[c]
Blueray Furnace	Distillate oil	New design	--	--	1.0	--	--	0	--	--	2.7

[a] Bias: Biased burner firing; BOOS: Burners out of service; FGR: Flue-gas recirculation; OFA: High overfire air; LEA: Low excess air; WI: Water injection

[b] Not analyzed

[c] $SO_4^=$ not included

class are quite hazardous, priority was given to obtaining data on these emissions in the NO_x EA test program.

Table 3-29 shows total SASS train organic determination data for the tests performed. As noted in Section 3.1 discussions, infrared analysis of sample extracts showed the organic species in the samples were in the aliphatic hydrocarbon, ether, ester, aromatic, and carboxylic acid categories. The data in the table indicate, though, that as was the case for CO and HC emissions, emission of these higher modular weight organics remain relatively unchanged with NO_x control application.

Table 3-30 shows the results of the Gas Chromatography/Mass Spectrometry (GC/MS) analysis of SASS train samples for the tests for which the analysis was performed. In all of these tests at least the 11 POM species shown in Table 3-31 were screened. For the Crist Unit 7 and Moss Landing Unit 6 tests analyses were made for the POM species and organic priority pollutants listed in Table 3-32.

Table 3-30 shows that, in general, POM emissions increase with NO_x control application, though, as noted from Section 3.1, these increases are moderate. In addition, the POM species found in the sample were not the highly carcinogenic compounds; only the less toxic POMs were identified. It is interesting to note that, in the Crist and Moss Landing analyses for the organic priority pollutants, none, including 2,3,7,8-Tetrachlorodibenzo-p-dioxin (2,3,7,8-TCDD) were found.

3.3 SUMMARY

From the evaluation of the results of the NO_x EA field test program, it can be concluded that:

- For the sources tested, the flue gas stream presents the greatest potential hazard
- NO_x and SO_2 are the potentially most hazardous flue gas pollutants
- Flue gas potential hazard is decreased or, at worst, does not increase with applying the combustion modifications tested; changes in emissions due to day to day fuel composition changes are often of greater magnitude than those attributable to NO_x control

Table 3-29. Effects of Controls Tested on Flue Gas SASS Organic Emissions

Test	Fuel	Control[a]	Organic Emissions (mg/dscm)		
			Baseline	Intermediate NO_x	Low NO_x
Kingston Unit 6	Coal	BOOS	0.124	--	0.834
Crist Unit 7	Coal	BOOS	4.23	2.320	0.722
Moss Landing Unit 6	Residual and crude oil	FGR, BOOS/FGR	4.38	1.37	1.43
Stoker Site A	Coal	OFA	1.00	--	1.79
Stoker Site B	Coal	LEA	0.924	--	1.37
T.H. Wharton Unit 52	Distillate oil	WI	1.30	--	1.10
Blueray Furnace	Distillate oil	New design	0.7-12.1[b]	--	26.3

[a] BOOS: Burners out of service;
FGR: Flue gas recirculation; OFA: High overfire air;
LEA: Low excess air; WI: Water injection

[b] Range of emissions from tests of conventional furnaces (Reference 3-3)

Table 3-30. Effects of Controls Tested on Flue Gas POM Species Emissions (μg/dscm)

POM Species	Crist Unit 7			Moss Landing Unit 6			Site A		T.H. Wharton Unit 52		Blueray Furnace
	Baseline	BOOS 2	BOOS 1	Baseline	FGR	BOOS/FGR	Baseline	Low NO_x	Baseline	Water Injection	Cyclic
Chrysene/Benz (a)anthracene	--	--	0.1	--	--	0.1	--	--	--	--	--
Fluoranthene	0.1	0.1	0.2	--	0.1	0.1	--	--	--	0.5	0.03
Fluorene	--	--	0.3	--	--	0.1	--	--	--	--	--
Naphthalene	--	0.9	0.3	--	--	--	--	--	--	1.0	--
Phenanthrene/ Anthracene	0.6	1.0	0.9	0.1	0.2	0.7	--	--	0.5	1.0	0.77
Pyrene	0.1	0.3	0.3	--	--	0.2	--	--	--	0.5	0.01

Table 3-31. POM Analysis: Species Determined in All Tests

Anthracene
Anthanthrene
Benz(a)anthracene
Benzo(g,h,i)perylene
Benzo(a)pyrene
Benzo(e)pyrene
Coronene
Fluoranthene
Phenanthrene
Perylene
Pyrene

Table 3-32. Compounds for Which GC/MS Analysis Was Performed in Some Tests

Acenapthene[a]
Acenapthalene[a]
Anthanthrene[a]
Anthracene[a]
Benzidine[a]
Benzo(a)anthracene[a]
3,4-Benezofluoranthene[a]
Benzo(k)fluoranthene[a]
Benzo(g,h,i)perylene[a]
Benzo(a)pyrene[a]
Benzo(e)pyrene[a]
4-Bromophenyl phenyl ether[a]
Butyl benzyl phthalate[a]
Bis(2-chloroethoxy) methane[a]
Bis(2-chloroethyl)ether[a]
Bis(2-chloroisopropyl) ether[a]
2-Chloronaphthalene
4-Chlorophenyl phenyl ether[a]
Chrysene[a]
Dibenzo(a,h)anthracene[a]
Dibenzo(c,g)carbazole[a]
Dibenzo(a,h)pyrene[a]
Dibenzo(a,i)pyrene[a]
Di-n-butyl phthalate[a]
1,2-Dichlorobenzene[a]
1,3-Dichlorobenzene[a]
1,4-Dichlorobenzene[a]
Bis (2-ethylhexyl) phthalate[a]
3,3'-Dichlorobenzidine[a]
Diethyl phthalate[a]
7,12-Dimethyl benz(a)anthracene[a]
Dimethyl phthalate[a]
2,4-Dinitrotoluene[a]
2,6-Dinitrotoluene[a]
Di-n-octyl phthalate[a]
1,2-Diphenylhydrazine[a] (as azobenzene)
Fluoranthene[a]
Fluorene[a]
Hexachlorobenzene[a]
Hexachlorobutadiene[a]
Hexachlorocyclopentadiene[a]
Hexachloroethane[a]
Indenol(1,2,3-c,d)pyrene[a]
Isophorone
3-Methyl cholanthrene[a]
Naphthalene[a]
Nitrobenzene[a]
N-nitrosodiphenylamine[a]
N-nitrosodi-n-propylamine[a]
Perylene[a]
Phenanthrene[a]
Pyrene[a]
2,3,7,8-Tetrachlorodibenzo-[a] p-dioxin
1,2,3-Trichlorobenzene[a]

[a] Compound in calibration standard.

- The effluent streams from the sources tested are not mutagenic, and, in general, elicit nondetectable toxicity in bioassay testing
- The combustion modifications tested:
  - Have no effect, or increase only slightly, emissions of CO and vapor phase hydrocarbon
  - Have no effect on particulate emissions
  - Have no effect or tend to increase slightly emitted particle size distribution
  - Have no measurable effect on trace element emissions or on trace element partitioning tendencies
  - Have no effect, or decrease slightly SO_3 and particulate sulfate emissions
  - Have little effect on total higher molecular weight organic emissions
  - Increase POM emissions; but these are not increased to levels of potential environmental concern, and POMs emitted are the less hazardous species
- Essentially no emissions of the organic priority pollutants, including 2,3,7,8-TCDD could be detected from the sources tested

It must be emphasized, though, that the sources were only tested under steady operation, in short duration tests, and that the controls tested were the relatively straightforward current technology combustion modifications. Conclusions on the effects of advanced combustion modification controls, and on the potential environmental impacts of combustion sources under unsteady or transient operation must await future testing.

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SECTION 4

PROCESS EVALUATION OF COMBUSTION MODIFICATION CONTROLS

To provide a meaningful evaluation of combustion modification controls, not only must their NO_x reduction capabilities be determined but also their impacts on boiler operation and maintenance, operating costs, and effluent emissions other than NO_x. Therefore, consistent process analysis procedures were developed and applied to field test data collected in this program as well as in other tests performed to characterize combustion modification controls. The approach was to compare process variables that characterize the emission source under baseline or normal operating conditions to those under controlled or low NO_x modes of operation. Significant changes in the process variables were noted, and these were highlighted as real or potential problems and concerns.

The following subsections summarize the control effectiveness and process impacts, including energy and cost, of applying the major combustion modification controls to the major stationary source categories: utility boilers, industrial boilers, gas turbines, internal combustion engines, and residential heating systems. The analyses summarized are presented in greater detail in References 4-1 through 4-5.

4.1 UTILITY BOILERS

The following discussion summarizes the control effectiveness, potential process impacts, cost impacts, and future trends of applying combustion modification NO_x controls to utility boilers. Within each area of analysis, the discussion is organized by fuel type and control technique, the dominant factors.

4.1.1 Status of Control Alternatives

4.1.1.1 Coal-Fired Boilers

Currently the most commonly applied low NO_x technique for coal-fired boilers is staged combustion through the introduction of overfire air (OFA). This technique has been used in both retrofit and new unit applications. Application of burners out of service (BOOS), an alternate staging technique with retrofit application, is limited because it is often accompanied by a 10 to 25 percent load reduction. Average NO_x reductions of 30 to 50 percent (controlled emissions of 215 to 301 ng/J, 0.5 to 0.7 $lb/10^6$ Btu) can be expected with either technique in dry bottom boilers. Flue gas recirculation (FGR) has been tested, but found to be a relatively ineffective control for coal firing, giving only about 15 percent NO_x reductions. More recently, new low NO_x burners (LNB) have been installed on some units and found to be at least as effective as OFA. In fact, new wall-fired units currently being brought online generally rely on LNB to meet the 1971 New Source Performance Standard (NSPS). The combination of OFA with LNB has resulted in 40 to 60 percent NO_x reductions (controlled emissions of 172 to 258 ng/J, 0.4 to 0.6 $lb/10^6$ Btu).

There has been a steady improvement in combustion modification control technology over recent years. Figure 4-1 conceptually reviews the past, current, and projected development of major controls. As shown, current demonstrated technology is capable of 40 to 60 percent NO_x reductions, easily meeting the 1971 NSPS of 301 ng/J (0.7 $lb/10^6$ Btu) and in most cases the 1979 revised standard of 215 to 260 ng/J (0.5 to 0.6 $lb/10^6$ Btu). Ammonia injection, which reduces NO_x by introducing NH_3 as a reducing agent in the post combustion zone, is considered a near-term intermediate control option between current technology and the more distant advanced concepts. It is intermediate from the point of view of control effectiveness, achieving 40-60 percent NO_x reductions. It is also intermediate from the point of view of availability only now beginning to be tested on a demonstration scale. Furthermore, ammonia injection has many potential operational and environmental impacts that need to be assessed, as discussed later, as well as much higher projected costs than either current or the more promising combustion modification concepts. Current R&D programs, such as the development and demonstration of the EPA advanced low NO_x burner and the EPRI primary combustion furnace, should result in combustion modification techniques capable of meeting NO_x emission levels of 86-129 ng/J (0.2-0.3 $lb/10^6$ Btu).

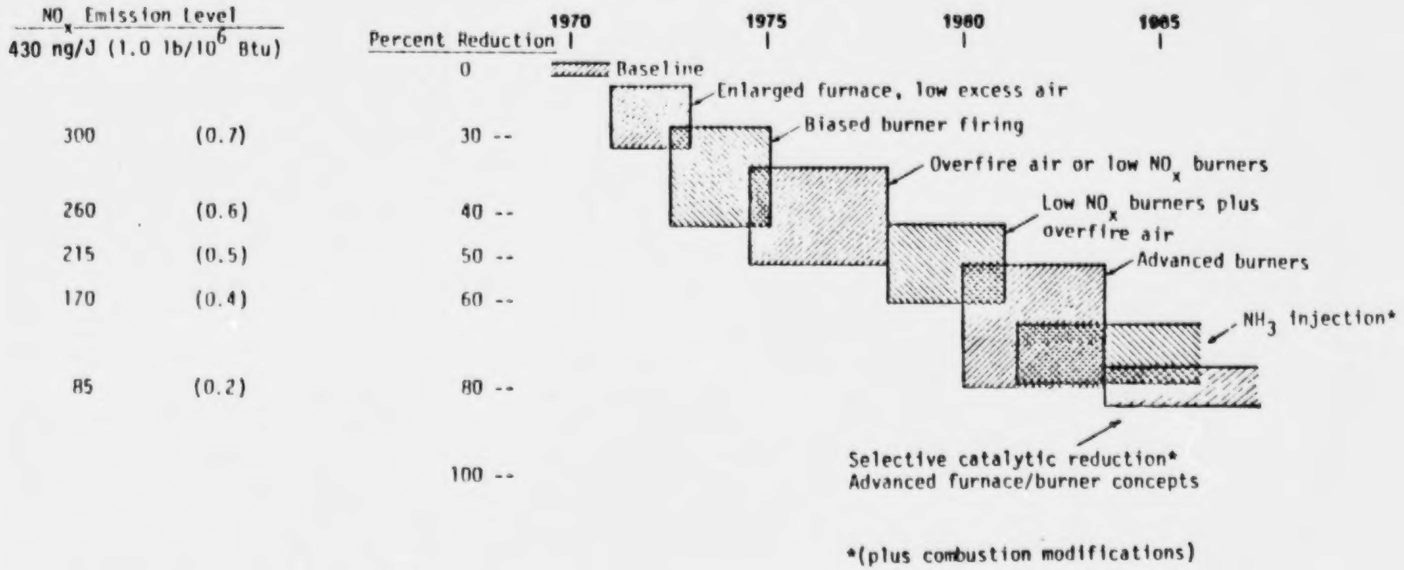

Figure 4-1. NO_x Control Development for Coal-Fired Boilers

4.1.1.2 Oil-Fired Boilers

The most commonly used low NO_x techniques for oil-fired boilers are staged combustion and flue gas recirculation (FGR), both employed with low excess air firing. These have generally been employed on a retrofit basis since few new oil-fired units are being installed. Other techniques which have been tested are water injection (WI) and reduced air preheat (RAP). However, these have found little application due to attendant efficiency losses.

Staged combustion has been applied through the use of overfire air ports (OFA) and by removing burners from service (BOOS). Typical NO_x reductions using OFA are 20 to 30 percent (controlled emissions of 150 to 172 ng/J, 0.35 to 0.4 $lb/10^6$ Btu), while BOOS has been slightly more effective giving 20 to 40 percent reductions (controlled levels of 129 to 172 ng/J, 0.3 to 0.4 $lb/10^6$ Btu). A load reduction may accompany the use of BOOS on some units. Flue gas recirculation also typically gives 20 to 30 percent NO_x reductions, but requires more hardware modifications. The combinations of BOOS or OFA with FGR has been most effective, resulting in 30 to 60 percent reductions (controlled emission of 86 to 172 ng/J, 0.2 to 0.4 $lb/10^6$ Btu). With FGR, OFA is preferred over BOOS because flame stability has been found to be more of a problem with the combination of FGR + BOOS.

There have been some R&D efforts by EPA and private industry to develop low NO_x emission burners for oil firing. Although no actual data have been released yet, the Babcock & Wilcox dual register low NO_x oil-fired burner has been successfully retrofitted on a utility boiler, achieving emissions below 129 ng/J (0.3 $lb/10^6$ Btu) (Reference 4-6). The combination of overfire air and low emission burners may potentially achieve emissions below 86 ng/J (0.2 $lb/10^6$ Btu). An oil-fired low NO_x burner is also under development by Southern California Edison to meet the stringent NO_x regulations for utility boilers in the Los Angeles area.

4.1.1.3 Gas-Fired Boilers

The most commonly applied NO_x control techniques for gas-fired boilers, as with oil-fired boilers, are staged combustion through the use of OFA or BOOS with FGR; however, flame stability may be of greater concern when FGR is combined with BOOS. Typical NO_x reductions under either OFA, BOOS, or FGR are 30 to 60 percent (controlled emissions of 86 to 150 ng/J, 0.2 to 0.35 lb/10^6 Btu). The combination of staged combustion and FGR is capable of 50 to 80 percent reduction (controlled levels of 43 to 108 ng/J, 0.1 to 0.25 lb/10^6 Btu).

There are no major efforts toward developing a low NO_x burner or other new combustion modification techniques for gas firing because NO_x emissions under current control techniques are already relatively low, and no new oil- or gas-fired utility boilers are being sold currently.

4.1.2 Process Impacts of Controls

4.1.2.1 Coal-Fired Boilers Conventional Combustion Modifications

The effects of low NO_x operation on coal-fired boilers are summarized in Table 4-1. The table describes experience obtained through field test programs on the several units listed. The major concerns regarding low NO_x operation on coal-fired boilers have been the effects on boiler efficiency, load capacity, water wall tube corrosion and slagging, carbon loss, heat absorption profile, and convective section tube and steam temperatures.

In most past experience with staged combustion, optimal excess air levels have been comparable to those used under baseline conditions. In these cases the efficiency of the boiler would remain unaffected if unburned carbon losses do not increase appreciably. However, in some cases when, due to nonuniform fuel air distribution or other causes, the excess air requirement increases under staged firing, a significant decrease in efficiency occurs. From Table 4-1, it is seen that efficiency decreases of up to 1 percent have been experienced. It is also seen that the same boiler (Widows Creek No. 5) tested at a different time with BOOS showed an average increase in efficiency of 1 percent.

Many new boilers now come factory equipped with OFA ports. Older boilers can be retrofitted with OFA ports, or can operate with minimal hardware changes under BOOS firing. BOOS firing is normally accomplished by shutting off one or more pulverizers supplying coal to the upper burner levels. If the other pulverizers cannot handle the extra fuel to maintain the total fuel flow constant, boiler derating will be required. From Table 4-1 it is seen that boiler derating of 10 to 25 percent is not uncommon with BOOS firing.

Table 4-1. Effect of Low NO_x Operation on Coal-Fired Boilers[a]

Boiler	Low NO_x Technique	Boiler Efficiency	Corrosion	Load Capacity	Carbon Loss in Flyash	Dust Loading	Part. Size Distribution	Other Effects, Comments
Tangential								
Barry No. 2	BOOS	Unaffected	Measured 75% increase, but within normal range	20% derate	Slight increase	~100% increase	--	Minor changes in heat absorption profile SH attemperation increased by 70%
	OFA	Unaffected	Measured 70% increase, but within normal range	Unaffected	Slight increase	~100% increase		Minor changes in heat absorption profile SH attemperation increased over 200%
Columbia No. 1	OFA	Unaffected	No change	Unaffected	Slight increase	--	--	Minor changes in heat absorption profile SH attemperation increased by 70%
Huntington Canyon No. 2	OFA	Unaffected	Measured 25% decrease, but within normal range	Unaffected	Slight increase	--	--	Minor changes in heat absorption profile No SH attemperation required
Barry No. 4	LEA, BOOS	Unaffected	No significant change	20% or more derate with BOOS	~50% average decrease	~50% average increase	--	
Navajo No. 2	LEA, BOOS, OFA	Unaffected	No significant change	Unaffected	No change	~40% average increase	No change	
Comanche No. 1	OFA	Unaffected	No significant change	Unaffected	~30% average decrease	~20% average decrease	No significant change	
Kingston No. 6	BBF	Unaffected	--	Unaffected	Unaffected	Unaffected	Unaffected	
	BOOS	0.5% average increase	--	20% derate	Unaffected	Unaffected	Unaffected	
Opposed Wall								
Harllee Branch No. 3	LEA, BOOS	0.6% average decrease	Slight increase	Up to 17% derate with BOOS	~130% average	~10% average increase	--	
Four Corners No. 4	LEA, BOOS	0.6% increase	No significant change	Up to 25% derate with BOOS	~50% average decrease	~15% average decrease	--	

Table 4-1. Concluded

Boiler	Low NO_x Technique	Boiler Efficiency	Corrosion	Load Capacity	Carbon Loss in Flyash	Dust Loading	Part. Size Distribution	Other Effects, Comments
Hatfield No. 3	BOOS	0.3% decrease	--	10% derate	~30% average increase	Unaffected	--	No slagging or fouling. No significant increase in tube temperatures.
	FGR	0.4% decrease in boiler efficiency. Some decrease in cycle efficiency due to RH. attemperation.	--	Unaffected	~120% average increase	Unaffected	--	Stable flames and uniform combustion. Increase in RH attemperation. No significant increase in tube temperatures.
E.C. Gaston No. 1	LNB, LEA, BOOS	0.3% decrease on average (LNB baseline)	No significant increase	Up to 30% derate (LNB with BOOS)	~130% average increase (LNB baseline)	~15% average increase (LNB baseline)	Shift towards smaller particles (LNB, with or without BOOS)	Unit retrofitted with low NO_x burners. Baseline, LEA and BOOS tests with LNB compared to baseline tests on sister boiler with no LNB.
Crist No. 7	BOOS	Unaffected	**Increase**	Unaffected	Slight increase	Unaffected	Unaffected	
Single Wall								
Widows Creek No. 5 (TVA Test)	BOOS	1% decrease	Results of tests inconclusive	Unaffected	30% increase	No significant increase	--	
Widows Creek No. 5 (Exxon test)	LEA, BOOS	1% average increase	No significant increase	Unaffected	30% average decrease	15% average decrease	--	
Widows Creek No. 6	LEA, BOOS	Unaffected	--	Unaffected	70% average increase	20% average decrease	--	
Mercer Station No. 1 (wet bottom)	LEA, Biased firing	Unaffected	No significant increase	Unaffected	80% average increase	10% average increase	No significant change	
Crist Station No. 6	LEA, BOOS	0.4% decrease	--	Up to 15% derate	60% increase	50% increase	--	

[a] -- denotes this parameter was not investigated.

The possibility of increased corrosion has been a major cause for concern with staged operation. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be susceptible to corrosion attack under reducing atmospheres. Local reducing atmosphere pockets may exist under staged combustion operation even when burner stoichiometry is slightly over 100 percent. The problem may be further aggravated by slagging as slag generally fuses at lower temperatures under reducing conditions. The sulfides in the molten slag may then readily attack tube walls. Still, as noted in Table 4-1, experience with most short-term tests has generally been that no significant acceleration in corrosion rates occurs under staged firing. Recent 12-month corrosion measurements by Exxon during low NO_x firing in a 500 MW boiler showed significantly higher corrosion rates with low NO_x operation (Reference 4-7). Nevertheless, the issue cannot be considered resolved until further results are available from long-term corrosion tests with measurements on units equipped with factory equipped NO_x controls. Insofar as slagging is concerned, short-term tests performed to date generally indicate no significant increase in slagging or fouling of tubes under staged combustion.

Increased carbon loss in flyash may occur with staged firing if complete burnout of the carbon particles does not occur in the furnace. High carbon loss will result in decreased boiler efficiency and may also cause electrostatic precipitator (ESP) operating problems. From Table 4-1, it is seen that increases in carbon loss vary over a wide range and can be as high as 70 to 130 percent of baseline values in some cases. However, increased carbon loss is not perceived as one of the major problems associated with staged combustion.

Extension of the combustion region to higher elevations in the furnace may result in potential problems with excessive steam and tube temperatures in retrofit applications. However, among the numerous short term combustion staging tests conducted, no such problems have been reported. In some tests where furnace and convective section tube temperatures were measured directly, no significant increase was found. Changes in heat absorption profiles were also found to be minor. Superheater attemperator spray flowrates tripled in one case under retrofit OFA operation, but in all cases were well within spray flow capacities of the units. Reheater attemperator spray flowrates did not show any increase due to staged operation, thus cycle efficiencies were not affected.

Many new wall-fired coal boilers are being fitted with low NO_x burners (LNB). These burners are designed to reduce NO_x levels either alone or in some cases in combination with OFA ports. Using the new burner designs has the advantage of eliminating or decreasing the need for reducing or near reducing conditions near furnace walls. Corrosion problems associated with reducing atmospheres should thus not arise with this system. Although low NO_x burner flames are generally less turbulent and hence longer than flames from normal burners, the combustion zone will probably not extend any farther up the furnace than with overfire air operation. Potential changes in heat absorption profile and excessive steam and tube temperatures are, therefore, less likely to occur.

As fuel and air flows are controlled more closely in LNB equipped systems, nonuniform distribution of fuel/air ratios leading to excessive CO generation or high excess air requirements should be eliminated. Boiler efficiencies should, therefore, not be affected, especially in new unit designs. However, Table 4-1 shows that the efficiency of one boiler decreased slightly (0.3 percent) when retrofitted with low NO_x burners. The decrease in efficiency was mainly due to the large increase in unburned carbon loss. However, such problems noted in retrofit applications can be avoided in units specifically designed with the low NO_x burners included. Corrosion rates inferred from tests with corrosion coupons showed no significant increase with the new burners. Some BOOS tests were also carried out on the LNB equipped boiler. A substantial decrease in NO_x emissions resulted, below those already achieved with the new burners alone. However, the boiler was derated by up to 30 percent. Other potential problems noted above as being associated with staged combustion could also arise with this type of firing.

It should be emphasized that the effects of NO_x control, in many cases, will be critically dependent on boiler operating conditions. Still, with proper design of retrofit systems and adequate maintenance programs, low NO_x operation should not result in a substantial increase in operational problems over normal boiler operation. Moreover, when NO_x controls are designed into new units, potential problems can be anticipated and largely avoided.

Advanced Techniques

Ammonia injection has numerous process limitations which have so far prevented its full scale commercialization as a NO_x reduction technique in coal-fired boilers. These limitations can be summarized as follows:

- Performance is very sensitive to flue gas temperature, and is maximized only within a 50K (90°F) temperature range from the optimum temperature of about 1240K (1770°F). This temperature sensitivity may require special procedures for load following. Addition of hydrogen to the ammonia reducing agent does lower the effective temperature range for NO_x reduction.
- Performance is very sensitive to flue gas residence time at optimum temperatures
- The ammonia feed rate must be closely tailored to the NO_x emissions to avoid high ammonia breakthrough or low NO_x reduction
- Successful retrofit application is highly dependent on the geometry of convective section of boiler
- Byproduct emissions such as ammonium bisulfate might cause operational problems such as air preheater fouling

Thus, ammonia injection should be considered to be still at the demonstration stage.

Other advanced NO_x control techniques under development, including the EPA advanced low NO_x burner and EPRI primary combustion furnace, are designed to further minimize some of the potential problems with conventional combustion modifications, such as losses in boiler efficiency and increases in corrosion rates.

4.1.2.2 Oil-Fired Boilers

The effects of low NO_x operation on oil-fired boilers are summarized in Table 4-2. The major concerns regarding low NO_x operation on oil-fired boilers are effects on boiler efficiency, load capacity, vibration and flame instability, and steam and tube temperatures.

Table 4-2. Effect of Low NO_x Operation on Oil-Fired Boilers[a]

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Tangential						
South Bay No. 4	LEA	5% increase	--	--	--	No adverse effects reported. Fan power consumption reduced.
	BOOS	Decrease in efficiency compared to LEA due to increased excess air requirements				No other adverse effects reported
	RAP	Unaffected due to special preheater design		--	--	Limited tests. NO_x control effectiveness not demonstrated.
Pittsburg No. 7	OFA and FGR	--	Slower startups and load changes	FGR fan vibration problems	High water wall tube temperatures	
SCE tangential boilers	BOOS and FGR	--	--	--	--	No adverse effects reported
Opposed Wall						
Moss Landing Nos. 6 and 7 (Early experience)	BOOS and FGR	Increased excess air requirements resulting in decreased efficiency	--	FGR fan and duct vibration, furnace vibration problems. Associated flame instability.	--	High furnace pressures. Increased FGR and forced draft fan power consumption.
Moss Landing No. 6 (NO_x EA tests)	FGR	Unaffected	Unaffected	None	No attemperation changes required	
	BOOS and FGR	Unaffected	Unaffected	None	No attemperation changes required	Unit currently operating under low NO_x continuously
Ormond Beach Nos. 1 and 2	BOOS and FGR	Increased excess air requirements resulting in decreased efficiency	10 to 15% derate due to maxed FD fan capacity	Flame instability and associated furnace vibration	--	Flame detection problems due to change in flame characteristics
	Water injection	Increased sensible and latent stack losses	--	--	--	Limited tests carried out with WI at partial loads. Excess air requirements increased.

Table 4-2. Concluded

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
SCE B&W Units	BOOS and FGR	FGR reduced minimum excess air requirements increasing unit efficiency	--	Boiler vibration problems	--	Flame detection problems due to change in flame characteristics
Sewaren Station No. 5	LEA, BOOS	--	--	--	--	Tests carried out at partial loads. No adverse effects reported. Particulate loading and size distribution unaffected.
Single Wall						
Encina Nos. 1, 2 and 3	LEA and BOOS (2 burners on air only)	Increased unit efficiency. Some adverse effect on cycle efficiency due to lower steam temperatures.	--	--	Decrease in SH & RH steam temperature	No other adverse effects reported
	BOOS (3 burners on air only)	Increased excess air requirements resulting in reduced efficiency	5% derate due to maxed ID fan capacity	In most tests no flame instability or blowoff noted	Intermittent flame carryover to SH inlet but tube temperature limits not exceeded	No abnormal tube fouling, corrosion or erosion noted. Increased tendency to smoke and obscure flame zone.
Turbo						
South Bay No. 3	Airflow adjustments	Slight reduction in EA resulting in slight increase in efficiency	--	--	--	No adverse effects reported
	Water injection	6% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported
	Reduced air preheat	Reduction in efficiency greater than that with water injection	--	--	--	Limited tests
Potrero No. 3-1	OFA and FGR	Higher excess air requirements, but addition of economizer surface expected to improve efficiency	5% derate due to excessive tube temperatures	Side to side windbox oxygen cycling	Tube and steam temperature limits approached. Increased SH tube failures.	Increased tendency to smoke required higher minimum excess O_2 levels. RH surface removed to avoid excessive RH steam attemperation. Larger economizer installed to compensate for RH surface removal.

[a] -- denotes not investigated.

Staged combustion operation generally increases the minimum excess air requirements of the boiler, which may result in a loss in boiler efficiency. In extreme cases when the boiler is operating close to the limits of its fan capacity, boiler derating may be required. Derates of as much as 15 percent have been required in some cases due to the lack of capability to meet the increased airflow requirements at full load. In addition, under BOOS firing the fuel flow to the active burners must be increased if load is to remain constant. In many cases, it has been necessary to enlarge the burner tips in order to accommodate these increased flows.

Other potential problems attendant with applying staged combustion on a retrofit basis in oil-fired boilers have concerned flame instabilities, boiler vibrations, and excessive convective section tube temperatures. However, in past experience, none of these problems has been significant. Staged operation can result in hazy flames and obscure flame zones. Thus new flame scanners and detectors are often required in retrofit applications. In addition, because staged combustion produces an extended flame zone, flame carryover to the convective section may occasionally occur. However, in one case where intermittent flame carryover occurred, no excessive tube temperatures were recorded.

Similarly, there are a number of potential problems which can occur in retrofit FGR applications. The most common problems, such as FGR fan and duct vibrations, can usually be avoided by good design. Other problems such as flame instability, which can lead to furnace vibrations, are caused by the increased gas velocity at the burner throats. Modifications to the burner geometry and design such as enlarging the throat, altering the burner tips, or adding diffuser plates or flame retainers, may then be required.

Another potential problem sometimes associated with FGR is high tube and steam temperatures in the convective section. The increased mass velocities which occur with FGR cause the convective heat transfer coefficient to rise. This, coupled with reduced furnace heat absorption, can give rise to high convective section gas temperatures. Increased mass flowrates in the furnace may also cause furnace pressures to increase beyond safe limits.

The combination of staged combustion and FGR is very effective in reducing NO_x emissions. However, the potential problems associated with each technique are also combined. Tube and steam temperature problems in the upper furnace area of concern, as both combustion staging and FGR tend to increase upper furnace temperatures and convective section heat transfer rates. In addition, boiler efficiencies usually decline slightly with combined staged combustion and FGR firing due to higher excess air requirements and greater fan power consumption.

As with coal-fired boilers, before low NO_x techniques are instituted on an oil-fired boiler, it is important to assure that it is in good operating condition. Uniform burner air and fuel flows are essential for optimal NO_x control. However, potential adverse effects for retrofit NO_x control systems can be minimized by proper design and installation. Thus, many of the problems experienced in the past can now be avoided.

4.1.2.3 Gas-Fired Boilers

The effects of low NO_x operation on gas-fired boilers are summarized in Table 4-3. The effects of low NO_x firing on gas-fired boilers are very similar to those for oil-fired boilers. Usually, there is no distinction between oil- and gas-fired boilers as they are designed to switch from one fuel to the other according to availability. Since boiler design details, NO_x control methods, and the effects of low NO_x operation are similar for gas- and oil-fired units, most of the above discussion of applicable NO_x control measures for oil-fired boilers and potential problems resulting applies. Some effects specific to gas-fired boilers alone are treated briefly in the following.

NO_x emissions oftentimes are difficult to control after switching from oil to gas firing. Residual oil firing tends to foul the furnace due to the oil ash content. Thus, NO_x control measures which have been tested on a clean furnace with gas may be found inadequate after oil firing due to the changed furnace conditions.

Boilers fired with gas usually have higher gas temperatures at the furnace outlet than fired with oil. The upper furnace and convective section inlet surfaces are thus subject to higher temperatures with gas firing. These temperatures may increase further under staged firing or FGR. Upper furnace and convective section tube failures and excessive

Table 4-3. Effect of Low NO_x Operation on Gas-Fired Boilers[a]

Boiler	Low NO_x Technique	Efficiency[a]	Load[a] Capacity	Vibration and[a] Flame Instability	Steam and Tube[a] Temperatures	Other Effects, Comments
Tangential						
South Bay No. 4	BOOS	Slight decrease in efficiency due to increased excess air requirements				No other adverse effects reported
Pittsburg No. 7	OFA and FGR	--	25% derate due to excessive steam temperatures slower load change response	Fan and duct vibration problems	High tube and RH steam temperatures	
Horizontally Opposed						
Moss Landing Nos. 6 and 7	OFA and FGR	0.8% decrease in cycle efficiency due to RH steam attemperation	Load curtailment to 50% after oil burns due to SH tube temperature limits being exceeded	Furnace and duct vibration problems. Flame instability.	RH spray and SH tube temperature limits approached after oil burns upper wall tube failures	Furnace pressure limit approached. FGR fan power requirements increased by as much as 66%. Problems associated with switching to gas after oil burning could be eliminated only with complete water washing of furnace.
Pittsburg Nos 5 and 6	OFA and FGR	--	--	FGR fan and duct vibrations. Flame instability problems.	Upper water wall tube failures	Boiler initially restricted to manual operation due to problems with flame instability on automatic control
Contra Costa Nos. 9 and 10	OFA and FGR	--	--	FGR duct vibrations	High SH and RH steam temperatures. SH tube temperature limits being approached.	Furnace pressure limits approached after oil firing. FGR fan preheating required to reduce vibrations on cold boiler startups.
Single Wall						
Encina Nos. 1, 2 and 3	BOOS (2 and 3 burners out of service)	Low EA levels were possible even with BOOS, resulting in increased efficiency	No derate. Load pickup response not affected	Some pressure pulsing at corners of firebox	Some flame carryover to SH but no problems with high tube temperature or tube wastage	No other adverse effects reported

[a] -- denotes not reported or investigated

Table 4-3. Concluded.

Boiler	Low NO_x Technique	Efficiency	Load Capacity	Vibration and Flame Instability	Steam and Tube Temperatures	Other Effects, Comments
Turbo						
South Bay No. 3	Water injection	10% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported
Potrero No. 3-1	OFA and FGR	Installation of larger economizer expected to improve efficiency	5% derate due to problems with high temperatures	Side to side windbox oxygen cycling	Tube metal and steam temperature limits reached at high loads	Hardware modifications included partial RH surface removal to avoid excessive RH steam attemperation. Larger economizer then installed to compensate for smaller RH surface.

Table 4-4. Summary of Retrofit Capital and Operating Control Costs (1978 dollars)

Boiler/Fuel Type	Initial Investment ($/kW)	Annualized Indirect Operating Cost ($/kW-yr)	Annualized Direct Operating Cost ($/kW-yr)[a]	Total to Cost Control ($/kW-yr)[a]
Tangential/Coal-Fired				
OFA	0.96	0.22	0.34	0.57
Opposed Wall/Coal-Fired				
OFA	0.66	0.17	0.55	0.73
LNB	2.17	0.36	0.06	0.42
BOOS	0.09	5.70	26.40	32.10
Single Wall/Oil- and Gas-Fired				
BOOS	0.32	0.05	0.47	0.52
FGR/OFA	6.09	1.22	2.04	3.26

[a] Based on 7000-hour operating year. Typical costs only.

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steam temperatures are therefore more likely to occur with staged firing and FGR applied to gas-fired boilers. The situation may be aggravated further if switching to gas fuel occurs after an oil burn, as fouling will further reduce furnace absorption and, hence, increase gas temperatures. Excessive tube temperatures will usually require derating of the system. However, problems with gas firing are not commonly encountered at present due to the scarcity of natural gas fuel.

4.1.3 Cost Impact of Controls

The costs of representative boiler/control combinations were analyzed using annualized utility revenue requirement economics. Both retrofit and new boiler control costs were considered.

4.1.3.1 Retrofit Control Costs

Based on the cost analysis methodology presented in Reference 4-1, typical retrofit control costs (1978 dollars) are summarized in Table 4-4. The costs shown in the table should be considered only representative retrofit costs. They apply to retrofitting relatively new boilers, say 5 to 10 years old with at least 25 years of service remaining. With the exception of BOOS for coal-fired units, and FGR/OFA for oil- and gas-fired units, annualized control costs generally fall in the \$0.50 to 0.70/kW-yr, based on a 7000-hour operating year. For comparison, the cost of operating a power plant is approximately \$175/kW-yr.

Burners out of service was treated in the cost analysis not as a recommended control technique for coal firing but to show the prohibitively high cost of derating. This high cost was due principally to the need to purchase made up power from elsewhere and to account for the lost capacity of the system through a capital charge.

Based on Table 4-4, Table 4-5 presents projected retrofit control requirements for alternative NO_x emissions levels. Control techniques are also recommended to achieve each given NO_x emission level. These requirements and techniques, combined with the cost to control column, complete the cost-effectiveness picture.

Based on favorable process analysis results, it is evident from an examination of Tables 4-4 and 4-5 that OFA and low NO_x burners (LNB) are the preferred, cost-effective NO_x controls for coal firing. For high levels of NO_x control for coal-fired units (170 ng/J), both OFA and LNB

Table 4-5. Projected Retrofit Control Requirements for Alternate NO_x Emissions Levels

Fuel/NO_x Emission Level ng/J (lb/10^6 Btu)	Recommended Control[a]	Cost to Control \$/kW-yr[b]	Cost Effectiveness \$/kg NO_x Removed
Coal			
301 (0.7)	OFA	0.50 to 0.70	0.03 to 0.04
258 (0.6)	OFA	0.50 to 0.70	0.02 to 0.03
215 (0.5)	LNB[c]	0.40 to 0.50	0.01 to 0.02
172 (0.4)	OFA + LNB[c]	0.95 to 1.20	0.02 to 0.03
Oil			
129 (0.3)	BOOS	0.50 to 0.60	0.04 to 0.05
86 (0.2)	FGR + OFA	~ 3.00	~ 0.16
Gas			
86 (0.2)	BOOS	0.20 to 0.30	0.03 to 0.04
43 (0.1)	FGR + OFA	~ 3.00	~ 0.12

[a] LEA considered standard operating practice.
[b] Typical installation only; could be significantly higher; includes capital and operating costs.
[c] Technology not thoroughly demonstrated for retrofit yet.

may be appropriate. For more moderate levels of control, LNB are less expensive and more cost-effective than OFA in reducing NO_x in wall-fired units. However, retrofit of low NO_x burners may not be widely applicable.

As far as moderate control for oil- and gas-fired units, staged combustion via BOOS appears to be the preferred route, as indicated in Tables 4-4 and 4-5. Initial investment is minimized since there are not associated major hardware requirements, only engineering and startup costs. To reach the next level of NO_x control (86 ng/J for oil, 43 ng/J for gas), FGR with OFA would seem to be in order. However, the increase in cost from $0.52/kW/yr for BOOS to $3/kW-yr for FGR and OFA does not make the option attractive. Besides, from a regulatory point of view, requirement of the emission level achievable with FGR and OFA would not be particularly attractive since oil- and gas-fired units with BOOS would already have very low NO_x emissions (129 ng/J for oil, 86 ng/J for gas) compared to coal-fired units.

4.1.3.2 Control Costs for New Boilers

Estimating the incremental costs of NO_x controls for new boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, though effective in reducing NO_x emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical new unit has been enlarged to reduce slagging potential and allow the burning of poorer quality fuels. But this also reduces NO_x due to the lowered heat release rate. Thus, since the design change would have been implemented even without the anticipated NO_x reduction, the cost of that design modification should not be attributed to NO_x control.

Babcock & Wilcox has estimated the incremental costs of NO_x controls on a coal-fired boiler designed to meet 1971 NSPS (Reference 4-8). The two units used in the comparison were identical except for NO_x controls on the NSPS unit which included:

- Replacing the high turbulence, rapid-mixing cell burner with the limited turbulence dual register (low NO_x) burner
- Increasing the burner zone by spreading the burners vertically to include 22 percent more furnace surface

- Metering and controlling the airflow to each row of burners using a compartmented windbox

To provide these changes for NO_x control, the price increase was about \$1.87 to \$2.67/kW (1978 dollars). If these costs are annualized, they translate to \$0.30 to 0.43/kW-yr.

In addition, Foster Wheeler has performed a detailed design study aimed at identifying the incremental costs of NO_x control to meet 1971 NSPS (Reference 4-9). Foster Wheeler looked at three unit designs with the following results:

	Boiler Design	Relative Cost
Unit 1:	Pre-NSPS base design	100
Unit 2:	Enlarged furnace, no active NO_x control	114
Unit 3:	NSPS design; enlarged furnace, new burner design, perforated hood, overfire air, boundary air	115.5

For a pre-NSPS coal-fired boiler costing about \$100/kW in 1969, or \$192/kW in 1978 construction costs, the incremental cost of active NO_x controls (LNB plus OFA) is \$2.97/kW, or about \$0.47/kW-yr annualized. The Foster Wheeler estimate, which includes both LNB and OFA, thus agrees quite well with the Babcock & Wilcox estimate, which includes only LNB and associated equipment.

Comparing these costs with the retrofit costs (0.40 to 0.70 \$/kW-yr for LNB or OFA) presented in Table 4-5 and considering the better NO_x control anticipated with NSPS units, it is certainly more cost effective to implement controls on new units. Furthermore, fewer operational problems are expected with factory installed controls.

4.1.3.3 Estimated Costs for Advanced Controls

Compared to the \$0.30 to \$0.50/kW-yr cost of preferred combustion modification controls for new coal-fired boilers, alternative NO_x control techniques, ammonia (NH_3) injection and selective catalytic reduction (SCR), neither of which represent demonstrated technology, are projected to cost significantly more: about \$8.50/kW-yr for NH_3 injection (References 4-10 and 4-11), and \$60 to \$80/kW-yr for SCR

(References 4-10, 4-12, and 4-13). However, these latter two techniques have the potential for achieving lower NO_x emission levels from coal firing 129 ng/J (0.3 lb/10^6 Btu) for NH_3 injection and 43 ng/J (0.1 lb/10^6 Btu) for SCR. These control levels are on the basis of conventional combustion modifications already having been applied.

Advanced combustion modification concepts under development, such as the EPA advanced low NO_x burner (Reference 4-14) and EPRI primary combustion furnace (Reference 4-15), are targeted to achieve NO_x emission levels around 86 ng/J (0.2 lb/10^6 Btu) on a commercial basis in the 1980's. Projected cost for the EPRI furnace is $4/kW or $0.80/kW-yr (Reference 4-16). The EPA advanced burner costs should fall in the same range. Thus developing advanced combustion modifications should eventually prove much more cost-effective than the developing post combustion techniques; however, the latter techniques are currently closer to commercialization. Both combustion modifications and post-combustion concepts may be difficult to implement on existing boilers.

In conclusion, conventional combustion modifications are indeed a cost-effective means of control for NO_x, raising the cost of electricity less than 1 percent in most cases. Furthermore, the initial capital investment required should also only be of the order of 1 percent or less of the installed cost of a boiler. With the exception of post combustion NH_3 injection, advanced techniques such as advanced low NO_x burners and advanced burner/furnace concepts have projected costs in the same range as conventional combustion modifications. Therefore, preferred current and projected combustion modification techniques are not expected to have any significant adverse economic impact.

4.1.4 Research and Development Trends

Modifying the combustion process conditions is currently the most cost-effective and best demonstrated method of effecting 20 to 60 percent reductions in NO_x emissions from utility boilers. Table 4-6 summarizes the capabilities of combustion modification controls. The methods in the best available control technology (BACT) and advanced technology categories are listed in preference of application, based on an assessment of their effectiveness, operational, energy, cost, and environmental impacts (Section 3), and commercial availability or R&D status.

Table 4-6. Combustion Modification NO_x Controls: Best Available Control Technology (BACT) and Advanced Technology

	Fuel	Control Technique	NO_x Control Level, ng/J	($lb/10^6$ Btu)
BACT	Coal	Overfire air	258	(0.6)
		Low NO_x burners	215	(0.5)
		Low NO_x burners plus overfire air	172	(0.4)
	Oil	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	86	(0.2)
	Gas	Burners out of service or overfire air	129	(0.3)
		Flue gas recirculation plus overfire air	43	(0.1)
Advanced Technology	Coal	Ammonia injection (1983)[a] (combined with BACT combustion modifications)	129	(0.3)
		Advanced low NO_x burners (1985)	86	(0.2)
		Advanced burner/furnace concepts (1985)	60	(0.15)
	Oil	Ammonia injection (1983) (combined with BACT combustion modifications)	43	(0.1)

[a] Estimated date of commercial availability of demonstrated technology.

Preferred conventional combustion modifications are indeed recommended for reducing NO_x emissions from utility boilers, with minimal adverse environmental or operational impacts. However, long-term testing and monitoring of field applications/demonstrations are continuing. Although the issue of possible increased corrosion with staged combustion in coal-fired boilers has been largely resolved in short-term tests, long-term corrosion testing, as under current EPA programs, should be completed to definitively establish that low NO_x firing does not have any adverse effects. Boiler efficiency should be closely monitored during field applications to give guidance to control developers on minimizing or eliminating efficiency losses. The current data base indicates that efficiency losses of 0 to 0.5 percent may be typical. The exact number is of significance; for example, a 0.25 percent loss in efficiency can translate to one-third of the annualized cost to control.

Research and development efforts on new combustion modification technology, such as advanced staged combustion, low NO_x burners and burner/furnace concepts, are continuing as they have the potential of further NO_x reduction capabilities with minimal adverse impacts.

4.2 INDUSTRIAL BOILERS

The majority of the combustion modification NO_x control concepts developed for utility boilers should, in principle, be applicable to industrial boilers. However, development and demonstration of specific techniques for the many specific boiler/fuel categories remain. Indeed, the existing data base consists primarily of short-term field tests of retrofit applications on a limited number of boilers. EPA is currently sponsoring a series of 30 day continuous monitor tests of industrial boilers operating at low emission conditions (Reference 4-20).

4.2.1 Status of Control Alternatives

Tables 4-7 through 4-10 summarize the effectiveness, operational, and cost impacts, and availability of the most promising control techniques for pulverized coal-, stoker coal-, residual oil-, distillate oil-, and natural gas-fired industrial boilers. It should be noted from the tables that many of these techniques are only in the development stage.

Results to date indicate that low excess air (LEA) or overfire air (OFA) form the best system for moderate (301 ng/J) and intermediate

Table 4-7. Promising Systems of NO_x Emissions Reduction for Pulverized Coal-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Availability
Low excess air	5 - 25	Increased boiler efficiency	Increased efficiency offsets capital and operating costs	Available
Overfire Air	5 - 30	Possible increased slagging, corrosion. Perhaps slight decrease in boiler efficiency.	Major modification. Marginal increase in cost for new units.	Commercially offered but not demonstrated for this boiler/fuel category
Reduced combustion intensity	10 - 25[c]	None. Best implemented as increased furnace plan area in new designs.	Major modification. Marginal increase in cost for new units. Retrofit load reduction may require replacement steam.	Technology transfer required from utility industry
Low NO_x burners	45 - 60	None expected	Potentially most cost-effective	1981 - 1983
NH_3 injection	40 - 60	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied

[c] Based on utility boiler experience

Table 4-8. Promising Systems of NO_x Emissions Reduction for Stoker Coal-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Availability
Low excess air	5 - 25	Possible grate overheat, clinker formation, increased corrosion. Close operator attention required.	Increased efficiency should partially offset costs	Available
Overfire air	5 - 25	Possible grate overheat. clinker formation, increased corrosion. Close operator attention required. Perhaps slight decrease in boiler efficiency.	Major modification of grate and OFA, probably costly. Present units have OFA for smoke control only	R&D
NH_3 injection	40 - 60	Possible implementation difficulties, fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modifications	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied.

Table 4-9. Promising Systems of NO_x Emissions Reduction for Residual Oil-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Availability
Low excess air	5 - 20	Increased boiler efficiency.	Increased efficiency partially offsets costs	Available
Staged combustion	20 - 50	Perhaps slight decrease in boiler efficiency	Major modification, perhaps costly	Commercially offered but not demonstrated for this boiler/fuel category
Low NO_x burners	20 - 50	None expected	Potentially most cost-effective	Commercially offered but not demonstrated
NH_3 injection	40 - 70	Possible implementation difficulties. Fouling problems with high sulfur fuels, load restrictions. Close operator attention required.	Several fold higher than conventional combustion modification	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly

[b] Incremental cost impact noting capacity/cost of boiler to which control is applied

Table 4-10. Promising Systems of NO_x Emissions Reduction for Distillate Oil- and Gas-Fired Boilers

Technique	Effectiveness[a] (% NO_x Reduction)	Operational Impact	Cost Impact[b]	Availability
Low excess air	5 - 15 (oil), 5 - 10 (gas)	Increased boiler efficiency	Increased efficiency should offset some of the costs	Available
Staged combustion	20 - 40 (oil), 25 - 45 (gas)	Perhaps slight decrease in boiler efficiency	Major modification, probably costly	Commercially offered but not demonstrated for this boiler/fuel category
Flue Gas recirculation	40 - 70 (oil) 45 - 75 (gas)	Possible flame instability which can be eliminated with proper engineering	Major modification, probably costly	Available
Reduced air preheat	20 - 55 (gas)	Replacing air preheater with economizer in new designs has negligible impact	None, other than engineering redesign of new units (if necessary)	Available
Low NO_x burners	20 - 50	None expected	Potentially most cost-effective	Commercially offered but not demonstrated

[a] Effectiveness based on control applied singly
[b] Incremental cost impact noting capacity/cost of boiler to which control is applied

(258 ng/J) NO_x control for pulverized coal-fired industrial boilers. However, those boilers with high baseline NO_x emissions may need to use a combination of OFA and LEA to achieve the intermediate control level. Staged combustion combined with low excess air can achieve the stringent control level of 215 ng/J. Alternative controls include low NO_x burners (LNB) and ammonia injection; however, these latter two techniques are still under development.

Spreader stokers are the only major stoker boiler types with average uncontrolled NO_x emissions as high as 258 ng/J. Low excess air and overfire air constitute the best candidate control systems capable of reductions to 215 ng/J. Any NO_x reduction beyond this level can only be achieved with NH_3 injection, possibly down to 129 ng/J. The other major stoker types, chain grate and underfeed, have average uncontrolled NO_x emissions below 172 ng/J. Control of these units to 129 ng/J is possible with LEA.

The candidate best control systems for residual oil-fired industrial boilers are low excess air, low NO_x burners, and staged combustion. Low NO_x burners, once developed are expected to reduce NO_x emissions to the 86 ng/J level. Staged combustion is not a demonstrated technique and may not be feasible for the smaller packaged boilers. An alternative control is NH_3 injection. Candidate best control systems for distillate oil- or gas-fired boilers are reduced air preheat, flue gas recirculation, and low NO_x burners, in that order, each capable of lowering NO_x to 65 ng/J. Reduced air preheat combined with flue gas recirculation or with low NO_x burners may potentially reduce NO_x emissions to 43 ng/J. The preferred method of reduced air preheat is to substitute, if possible, an economizer in place of an air preheater in a new boiler design.

4.2.2 Process Impacts of Controls

Possible operational impacts with NO_x control were summarized in Tables 4-7 through 4-10. The major potential impacts are increased slagging and corrosion for coal firing, and slight decreases in boiler thermal efficiency for all fuels. Controls for stokers are not well developed, and the only available technique, LEA+OFA, can lead to severe clinker formation if not applied with care. Ammonia injection may suffer implementation difficulties and fouling problems. In general, however, with proper engineering, development, and implementation, the developed combustion modification NO_x controls should not have major adverse operational impacts if properly applied.

4.2.3 Cost Impact of Controls

The primary contributions of combustion modification NO_x controls to steam cost changes are the equipment modification costs and changes in thermal efficiency and fan power demand. Tables 4-11, 4-12, and 4-13 give estimated costs of applying low excess air, staged combustion, and flue gas recirculation, respectively, to new industrial boilers. Retrofit controls can easily cost twice that for new units.

Three potential control techniques are not included in the cost tables: reduced air preheat, low NO_x burners, and ammonia injection. Reduced air preheat is effective for distillate oil- and gas-fired units and recommended only for those boilers which can incorporate an economizer in place of an air preheater in their new designs, in which case there is no significant cost impact. Low NO_x burners and ammonia injection are still in the developmental stage, so costs are not yet firmly established. Current estimates indicate that low NO_x burner (LNB) operation will cost no more than staged combustion (SCA) and in fact, LNB may have an even smaller effect on steam price than SCA (Reference 4-2). Ammonia injection on a typical 59 MW (200×10^6 Btu/hr) heat input boiler is estimated to be about \$236,000, a 3.5 percent increase in capital cost for a pulverized coal unit. The incremental steam cost is estimated to be \$0.22/Mg steam (\$0.10/10^3 lb steam) or a 2.5 percent increase in steam cost.

Table 4-14 summarizes the preferred order of applying NO_x controls, along with potentially achievable control levels and cost-effectiveness. Low excess air is the method recommended to be first considered since it can reduce fuel costs. Low NO_x burners are a promising technique since they should allow both low NO_x and LEA operation, and thus save fuel while lowering NO_x emissions. Staged combustion is the next best method, unless fuel switching problems make it impractical, since the optimal air port location is fuel dependent. If staged combustion cannot be used, flue gas recirculation is the next most cost-effective technique for oil- and gas-fired units. At least one manufacturer currently offers an oil- or gas-fired unit equipped with flue

Table 4-11. Estimated Cost of Low Excess Air Operation for New Boilers

Boiler Fuel Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost $1000	Annualized Costs			Percent Change in Cost of	
				Fixed	Operating	Total	Boiler	Steam
				Mills/ Mg steam	Mills/ Mg steam	Mills/ Mg steam		
Pulverized coal	59 (200)	15	27	13 (6)[a]	-28 (-13)	-15 (-7)	0.4	-0.1
Spreader stoker	44 (150)	15	22	16 (7)	-31 (-14)	-15 (-7)	0.5	-0.1
Chain grate stoker	22 (75)	15	17	26 (12)	-28 (-13)	-2 (-1)	1.2	0
Underfeed stoker	9 (30)	15	14	54 (24)	-23 (-10)	21 (14)	1.5	0.1
Residual oil watertube	44 (150)	20	17	12 (5)	-75 (-34)	-63 (-29)	1.9	-0.5
Residual oil firetube	4.4 (15)	15	9	91 (41)	-59 (-27)	32 (14)	9.0	0.1
Distillate oil watertube	29 (100)	10	14	16 (7)	-41 (-19)	-25 (-11)	3.4	-0.2
Distillate oil firetube	4.4 (15)	10	9	91 (41)	-26 (-12)	65 (29)	9.0	0.2
Natural gas watertube	29 (100)	5	14	16 (7)	-25 (-11)	-9 (-4)	4.0	-0.2
Natural gas firetube	4.4 (15)	5	9	91 (41)	-11 (-5)	80 (36)	9.0	0.3

[a] Numbers in parentheses are in units of mills/10^3 lb steam

Table 4-12. Estimated Cost of Staged Combustion Operation for New Boilers

Boiler Fuel Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost $1000	Annualized Costs			Percent Change in Cost of	
				Fixed	Operating	Total	Boiler	Steam
				Mills/ Mg steam	Mills/ Mg steam	Mills/ Mg steam		
Pulverized coal	59 (200)	25	47	24 (11)[a]	47 (21)	71 (32)	0.8	0.6
Spreader stoker	44 (150)	20	22	16 (7)	4 (2)	20 (9)	0.5	0.1
Chain grate stoker	22 (75)	15	17	26 (12)	6 (3)	32 (15)	1.2	0.2
Underfeed stoker	9 (30)	15	14	54 (24)	12 (5)	66 (29)	1.6	0.3
Residual oil watertube	44 (150)	35	32	23 (10)	80 (36)	103 (46)	5.5	1.2
Residual oil firetube	4.4 (15)	25	19	193 (88)	117 (53)	310 (141)	21.0	1.2
Distillate oil watertube	29 (100)	30	26	29 (13)	84 (38)	113 (51)	7.0	1.2
Natural gas watertube	29 (100)	30	27	29 (13)	69 (31)	98 (44)	7.0	1.6

[a] Numbers in parentheses are in units of mills/10^3 lb steam

Table 4-13. Estimated Cost of Flue Gas Recirculation Operation for New Boilers

Boiler Fuel Type	Heat Input MW (10^6 Btu/hr)	Percent NO_x Reduction	Capital Cost $1000	Annualized Costs			Percent Change in Cost of	
				Fixed	Operating	Total	Boiler	Steam
				Mills/ Mg steam	Mills/ Mg steam	Mills/ Mg steam		
Distillate Oil watertube	29 (100)	40	26	29 (13)[a]	135 (61)	164 (74)	7.0	1.7
Distillate oil firetube	4.4 (15)	40	19	192 (87)	175 (80)	367 (167)	21.0	1.2
Natural gas watertube	29 (100)	40	26	29 (13)	120 (54)	150 (67)	7.0	2.4
Natural gas firetube	4.4 (15)	40	19	192 (87)	159 (72)	351 (159)	21.0	1.7

[a] Numbers in parentheses are in units of mills/10^3 lb/steam

Table 4-14. Cost-Effectiveness of NO_x Controls

Type	Control Level ng/J ($lb/10^6$ Btu)	Control Technique	Control Cost mills/ Mg Steam	Cost Effectiveness \$/kg NO_x Reduced
Pulverized Coal	285 (0.663) 258 (0.6) 215 (0.5) 172 (0.4) 129 (0.3)	Baseline LEA OFA OFA + LNB OFA + NH_3 injection	-- 0 70 ~140 ~275	-- 0 0.3 ~0.4 ~0.5
Spreader Stoker	265 (0.616) 215 (0.5) 129 (0.3)	Baseline OFA NH_3 injection	-- 20 ~220	-- 0.1 ~0.5
Residual Oil Watertube	160 (0.372) 129 (0.3) 86 (0.2)	Baseline LEA LNB	-- -60 ~170	-- -0.6 ~0.7
Distillate Oil Firetube	70 (0.163) 65 (0.15) 43 (0.1)	Baseline LEA FGR	-- 65 367	-- 0.2 1.2
Natural Gas Firetube	40 (0.093) 24 (0.06)	Baseline FGR	-- 350	-- 2.0

gas recirculation. Ammonia injection is the least cost-effective technique and load changing may make it impractical. Also, whenever possible, an economizer is preferred over an air preheater as a fuel saving device since it does not raise NO_x levels.

In summary, combustion modification NO_x controls, once proven and demonstrated, should be a cost-effective means of control for industrial boilers raising steam costs by 1 to 2 percent in most cases. However, the initial investment required, especially for small boilers, may be a large fraction of the cost of the boiler itself, up to 25 percent when controls are installed on a new boiler and up to 50 percent when retrofitting the controls on an existing boiler. Factory installed controls on new boilers should prove more cost-effective than retrofit controls.

4.2.4 Research and Development Trends

As stated earlier, with the wide diversity of equipment types, data on the effectiveness and impacts of potential NO_x controls are lacking for many industrial boiler designs. EPA is currently sponsoring several field test programs demonstrating and evaluating combustion modification NO_x controls for industrial boilers. These programs include identification of optimal combustion conditions for 11 stoker coal-fired boilers, sponsored jointly with the Department of Energy (References 4-17 and 4-18), and field demonstrations of a low NO_x burner for gas firing (References 4-19 and 4-20). In addition, programs to develop an advanced low NO_x burner and advanced stoker concepts have been initiated (References 4-14 and 4-21). The results from these studies should help fill some of the control data gaps. In addition, several other field tests of these and other combustion controls are being planned, including 30-day continuous monitoring programs (Reference 4-20).

Recent tests of water/oil emulsions fired in special burners have shown this to be an effective control for particulate and organics emissions (Reference 4-32). Water/oil emulsions did not have any significant effect on NO emissions relative to fuel oil, however.

4.3 GAS TURBINES

NO_x controls for gas turbines are usually classified into two categories: wet techniques which inject water or steam into the combustion zone, and dry techniques which involve such combustion or firing modifications as controlled fuel/air mixing.

4.3.1 Status of Control Alternatives

Wet controls are the only currently available methods sufficiently developed to reduce gas turbine NO_x emissions below the NO_x NSPS (75 ppm at 15 percent oxygen) and already existing and more stringent local regulations. Wet controls work on the principle of thermal quenching -- effective lowering of peak flame temperatures thereby reducing NO_x generation. The required degree of control is obtained by altering the water-to-fuel ratio. NO_x emissions can be reduced approximately 45 percent using a 0.5 water/fuel ratio, to below 75 ppm at 15 percent oxygen. In fact, NO_x reductions up to 80 percent may be possible. However, depending on the water-to-fuel ratio and operating conditions, emissions of hydrocarbons and CO may increase.

Dry NO_x controls generally refer to combustor modifications and do not involve water or steam injection. A number of general concepts are currently being examined by dry control developers, including catalytic combustion, but one in particular is emerging as the most promising. The Pratt and Whitney Aircraft Group has successfully completed an EPA sponsored program in which the concepts of premixing and prevaporization of the fuel mixture and rich primary burning were demonstrated in a combustor scaled up to a 25 MW engine. All program goals were met. NO_x emissions were held below 75 ppm while CO emissions remained below 100 ppm. The technique appears effective for both "clean" fuels and high nitrogen fuels.

Other dry NO_x control programs have concentrated on the lean burning concept. This technique, when combined with prevaporization and premixing, is very effective in reducing NO_x when burning fuels low in fuel bound nitrogen, through reduction of thermal NO_x. However, lean burning may actually increase fuel NO_x production. Therefore, given the present fuel trends toward dirtier fuels high in fuel nitrogen, and noting the success of rich burning techniques in controlling both thermal and fuel NO_x, rich burning appears to be most promising approach for future low NO_x gas turbine combustor designs.

Other organizations are developing different dry control concepts with various degrees of success. Many of these programs are being conducted with meeting the aircraft jet engine emissions standards in mind, thus the designs and dry control concepts are being evaluated for aircraft engines which burn clean jet fuels. There is some disagreement as to whether this approach to dry NO_x controls will be adaptable to stationary gas turbines designed to fire a variety of fuels.

4.3.2 Process Impacts of Controls

There is considerable disagreement about the impact that wet controls have on the daily operations and maintenance of gas turbines. An increase in engine heat rate, manifested as a maximum of 5 percent increase in fuel usage, is the most significant impact on operations. This may be offset somewhat by increased power output caused by the increase in mass throughput. Periodic recharging of the water purification system will most certainly be required. Indeed, a full time operator/maintenance person may even be warranted for some installations. Some users have reported significant maintenance problems with the water treatment system itself and internal turbine problems due to water use. The nature of the latter type generally fall into one of the following two categories: hot parts embrittlement or particle deposition and contamination. It appears these items are not only affected by water quality, water/fuel ratio, and equipment types, but by day-to-day operations and maintenance procedures. At least two utilities have accumulated over 50,000 hours of wet NO_x control experience and have experienced no significant problems or outages directly attributable to the control technique.

Most dry control techniques are being developed with the intent of minimizing emissions of CO and UHC as well as NO_x. Manufacturers have had varying degrees of success. While many designs face a NO_x/CO trade-off, the rich-burn, quick-quench combustor appears to have isolated NO_x control from CO control.

In contrast, the problem becomes particularly difficult for lean burn combustors during off-design conditions when combustion is not very efficient. While formation of NO_x is somewhat inhibited under these conditions, incomplete oxidation of CO and UHC is favored. Lean designs partially solve these problems by having variable equivalence ratios. At off-design conditions, equivalence ratios are near stoichiometric to minimize UHC and CO while lean burning is used to minimize NO_x at full power.

Since dry controls are essentially modified, although more complex, conventional combustors, there probably will not be any additional impact on operations and maintenance. Still, all of the problems manufacturers are experiencing in the developmental stage must be solved before these concepts are employed on full scale engines. Moreover, new problems to be solved will undoubtedly surface during the scale-up process. Currently, it is not expected that dry controls will significantly affect heat rate. Combustor liners may have to be replaced more frequently than with conventional combustors.

4.3.3 Cost Impacts of Controls

Implementing wet controls can significantly affect the total operating cost of a stationary gas turbine, which varies greatly among users. Tables 4-15 through 4-18 compare controlled and uncontrolled capital and operating costs for typical utility and industrial gas turbines. Various utilities have reported capital costs ranging from \$4/kW in 1975 dollars to almost \$23/kW in 1978 dollars. (For comparison, a typical utility gas turbine will cost, in total, approximately \$150/kW in 1978 dollars.) Actual costs are very site specific and depend to a great extent on the required water purification equipment and to a lesser extent on turbine modifications. Also, a fuel penalty resulting from an increased heat rate with water injection is a significant portion of this increased expense. The total annualized cost of wet controls, including capital and operating costs, raises the cost of electricity by about 2 to 5 percent.

At this stage of development of dry controls, it is difficult to accurately predict their associated costs. Whether development costs are passed on to the user and the market size over which these costs can be spread will be major factors in determining the magnitude of dry control costs. It appears that dry NO_x controls which have development expenditures included in their total cost will cost somewhat less than wet NO_x controls for a comparably sized unit. If development costs are not passed on, dry control combustors are expected to be only nominally more costly than existing combustor models.

Table 4-19 summarizes installed costs and annualized costs for various control techniques and NO_x emission levels. Wet controls are currently the preferred, indeed the only demonstrated NO_x control

Table 4-15. Estimated Operating Cost of Uncontrolled Utility Gas Turbine (50 MW) (1978 Dollars)

Use	Peaking	Midrange	Baseload
Installed cost ($/kW)	150	150	150
Heat rate (MJ/kW)	10.7	10.9	10.9
Fixed costs (% of installed cost)	20	20	20
Operating and maintenance (% of installed cost)	3	3	3
Fuel cost ($/GJ)	2.84	2.84	2.84
Costs			
Fixed, operating, and maintenance mills/kWh)	69	8.6	4.3
Fuel (mills/kWh)	30	30.9	30.9
Total	100	40	35

Table 4-16. Estimated Cost of Water Injection for Utility Gas Turbines (1978 Dollars)

Use	Peaking	Midrange	Baseload
Size (MW)	50	50	50
Hours of operation per year	500	4000	8000
Water costs ($/m^3)	0.8	0.8	0.8
Water feed rate (m^3/h)	7.6	7.6	7.6
Installed cost ($/kW)	10.0	10.0	10.0
Annualized costs (mills/kWh)			
Fixed, operating, and maintenance	4.6	0.6	0.3
Water cost	0.1	0.1	0.1
Fuel penalty	0.6	0.6	0.6
Capacity enhancement	-1.3	-0.2	-0.1
Total (mills/kWh)	4.0	1.1	0.9
% change over uncontrolled	4.0	2.7	2.6

Table 4-17. Estimated Costs for Uncontrolled Industrial Gas Turbine (1978 Dollars)

Use	Midrange	Baseload
Size (kW)	2775	2775
Installed cost ($/kW)	300	300
Heat rate (MJ/kWh)	14	14
Fixed costs (% of installed cost)	20	20
Operating and maintenance (% of installed cost)	5	5
Fuel cost ($/GJ)	2.84	2.84
Hours per year operation	4000	8000
Annualized costs (mills/kWh)		
Fixed, operating, and maintenance	18.75	9.38
Fuel	39.8	39.8
Total	59	49

Table 4-18. Estimated Costs of Water Injection for Industrial Gas Turbine (1975 Dollars)

Use	Midrange	Baseload
Size (kW)	2775	2775
Installed costs ($/kW)	30	30
Hours per year operation	4000	8000
Water cost ($/m^3)	0.8	0.8
Flowrate (m^3/h)	0.4	0.4
Annualized costs (mills/kWh)		
Fixed, operating, and maintenance	1.87	0.94
Fuel penalty	0.80	0.80
Water costs	0.10	0.10
Total (mills/kWh)	2.8	1.8
% of uncontrolled	4.7	3.7

Table 4-19. Projected Control Requirements for Alternate NO_x Emission Levels

NO_x Emission Level (ppm @ 15% O_2)	Control Technique	Install. Cost $/kW	Annualized Cost mills/kWh
130	Water Injection	8	3.5
75	Water Injection	10	4.0
40	Water Injection	12	4.7
75	Dry controls (1983)	NA	NA
5	Catalytic combustion (1985-1990)	NA	NA

Notes:

Peaking utility turbine, baseline NO_x -- 175 ppm @ 15% O_2
Based on Table 4-21 assumptions and data: 1978 dollars
Fuel penalty and capacity enhancement assumed linear with water/fuel ratio
Dry control costs expected to be somewhat less than wet controls

technique which meets the proposed NO_x NSPS for stationary gas turbines. Although the capital costs of water injection can be significant, approximately 10 percent of total unit cost on a per kW basis, annualizing that cost along with operating costs results in an incremental cost of electricity of only 2 to 5 percent. As noted above, though, dry controls are expected to cost somewhat less than wet controls.

4.3.4 Research and Development Trends

A substantial data base supports the effectiveness of wet controls in reducing NO_x from stationary gas turbines. However, alternative techniques such as dry controls are being sought because of the high fuel penalty and additional operating and maintenance requirements associated with wet controls.

Furthermore, a significant amount of disparity exists in both capital and operating cost estimates for wet controls from users, manufacturers, and the EPA. Other than for large scale gas turbines where a few users could supply actual costs, data are primarily manufacturer and EPA cost estimates. Even for large scale units, data are sparse since most users are not yet required to control NO_x.

Specific areas where opinions differ regarding impacts due to wet controls include:

- Water injection cost data for capital equipment, operating and maintenance expenses
- The cost/benefit ratio of wet controls for small gas turbines (4 MW)
- Quantification of the fuel penalty due to increased heat rate and additional power output resulting from more mass throughput

Given the existing state of development of dry NO_x controls, it is not possible to perform a comprehensive analysis. The NO_x EA relied heavily on experimental combustor program literature and industry contacts to qualitatively assess the most promising dry control concepts. Since some of the developmental work is proprietary, the information is incomplete. Furthermore, the work conducted so far has generally been performed on a single combustor rig. Significant research and development will be required before these dry control concepts can be reliably applied to actual engines.

The available data for all dry NO_x control techniques only provide qualitative judgements and estimates when predicting costs, incremental emissions, and operations and maintenance impacts. It should be noted that dry controls while considered an emerging technology, are only 3 to 5 years from the first full scale application. Still, numerous changes in the preferred design, which could have a major impact on the predicted environmental effects, may occur.

As users and manufacturers gain experience, additional emissions data should be gathered and periodically evaluated during the life cycle of existing, modified, and new stationary gas turbines. This is necessary because dry NO_x control techniques are just evolving as a technology and there is a considerable lack of long-term operating experience with wet controls.

At present, it seems clear that dry NO_x controls have the potential to be the preferred control technology option for new gas turbines within 5 years. However, because dry controls are still in the development stage, few data exist for emission levels, control costs, and operation and maintenance impacts for dry controls applied to full scale engines. As the direction of dry controls research becomes evident, additional testing programs can be suitably designed to provide the proper data base. Then, as dry controls become commercially feasible and users gain operating experience, any additional data gaps may be filled accordingly. The types of gaps will primarily be additional operating and maintenance costs that can only be accurately predicted through long-term expense accounting. Only with long-term experience, as well as careful front-end tracking of dry control developments, can a comprehensive environmental assessment be performed. The task should not be extremely complicated for gas turbines. Dry controls do not require as much ancillary equipment as do wet controls, so in this regard, they can be considered less complex. Also, most manufacturers expect no additional costs over wet controls, nor do they expect any significant operational or maintenance impacts.

4.4 INTERNAL COMBUSTION ENGINES

4.4.1 Status of Control Alternatives

Table 4-20 lists the various combustion modification controls applicable to internal combustion (IC) engines and shows the NO_x

Table 4-20. NO_x Reduction and Fuel Consumption Penalties for Diesel, Dual Fuel, and Gas Engines

Control Approach		Engine Fuel Type					
		Diesel		Dual Fuel		Natural Gas	
		% NO_x Reduction	ΔBSFC, %[a]	% NO_x Reduction	ΔBSFC, %[a]	% NO_x Reduction	ΔBSFC, %[a]
Derate (D)	3%	--	--	--	--	<20	2
	6%	--	--	--	--	<40	3
	10%	--	--	<20	4	--	--
	20%	<20	4	--	--	--	--
	25%	5-23	1-5	1-33	1-7	5-90	2-12
Retard (R)	2°	<20	4	<20	3	--	--
	4°	<40	4	<40	1	<20	3
	8°	28-45	2-8	50-73	3-5	8-40	2-7
Air-to-Fuel (A)	2%	--	--	--	--	<20	2
	3%	--	--	<20	0	--	--
	5%	--	--	--	--	<40	7
	±10%	7-8	3	25-40	1-3	20-80	5-12
Manifold Air Temperature (M')	311K(100°F)	7-15	0-2	18-37	0-1	28	0
	315K(107°F)	--	--	--	--	<20	0
	318K(113°F)	--	--	<20	1	--	--
Internal EGR		5	2	--	--	<20	5
		--	--	--	--	5-35	0-8
External EGR	10%	<20	1	20	1	<20	0
		33	1	--	--	33	0
Retard and Manifold Air Temperature		<20	1	<20	1	<20	3
		10-24	0-1	25	2	30-40	5-6
Retard & Air-to-Fuel		<20	8	<20	1	<20	4
		<40	16	<40	2	<40	8
		35-65	5-26	56	2	17-52	4-11
Retard and Manifold Air Temperature and Air-to-Fuel		20	0	<20	2	<20	2
		--	--	40	3	<40	4
		--	--	--	--	40-65	6-7
Air-to-Fuel and Manifold Air Temperature		<20	2	--	--	--	--
		20-30	3	--	--	--	--
Water Injection H_2O/fuel ratio	50%	25-35	2-4	--	--	25-35	1-2
	100%			--	--	60-75	2-5
Catalytic Reduction (Projected)		50-80	0	50-80	0	50-80	0
Combustion Chamber Modifications (Projected)	Increased Mixing	10-30	<5	20-40	<5	20-40	<5
	Staged Combustion	10-30	0	10-30	0-7	10-30	0-2

[a] ΔBSFC is change in break specific fuel consumption.

reductions and fuel penalties associated with these controls as a function of engine type. Combinations of controls which may be readily applied are also shown. From this table it is apparent that the best available control techniques for large bore engines are: (1) retarded ignition or fuel injection, (2) air-to-fuel changes, (3) increased manifold air cooling, and (4) derating. These techniques can either be employed alone or in combinations with each other. However, the best combination will be very engine dependent. In general, retard is best for diesel-fueled engines, air-to-fuel ratio changes for natural gas, and either control for dual fuel. A 40 percent reduction in NO_x can usually be achieved without causing any major operational problems. Such reductions will be needed to meet the recently proposed NSPS for IC engines (600 ppm at 15 percent O_2 for diesel and dual fuel engines larger than 9.2ℓ displacement and 700 ppm at 15 percent O_2 for gas engines larger than 5.7 ℓ displacement). However, since the emissions of these engines vary greatly, the actual control level achievable also varies greatly.

4.4.2 Process Impacts of Controls

Since engines are currently optimized for minimum maintenance requirements and fuel use, any control technique which varies engine parameters from standard conditions will impact operation and maintenance. Some of these impacts have been well characterized, especially those from control techniques which involve engine operational changes. Other control techniques will require various degrees of evaluation before impacts are clearly understood.

Derate, air-to-fuel ratio changes, manifold air cooling, and ignition retard present the fewest problems in operation and maintenance. Derate has no impact mechanically and can improve durability because of lower operating temperatures and pressures achieved. However, additional engines may be required to replace the lost power. Fuel penalties are usually low.

Air-to-fuel ratio changes in the lean direction cause a power loss if larger blowers or turbochargers must be used. If the engine must be operated richer to reduce NO_x emissions, other emissions such as smoke and deposits can increase. This could cause an increase in engine maintenance. Changes in air-to-fuel ratio in either direction will also generally increase fuel consumption. Finally, operation at air-to-fuel ratios where misfiring or detonation occur can cause severe engine damage.

Increased manifold air cooling has little operational or maintenance impact for a unit that is already intercooled, but will increase the size of the heat exchanger, water or air pump, control system, and other system components. Of course, installing intercooling on an engine originally without the system will add maintenance attendant to additional temperature reductions. Changes in fuel consumption are small.

When properly applied, ignition retard has no serious mechanical drawbacks. Some increase in operational and maintenance time would be needed to ensure the degree of retard was always within safe limits. Increases in fuel consumption are moderate. Excessive amounts of retard, however, can create severe engine problems. Fuel consumption increases rapidly, power drops, misfiring can occur, and smoke levels increase. In addition, mechanical maintenance will increase if the exhaust temperature exceeds the safe limits for valves or the turbocharger (usually 920K (1200^0F)). More frequent engine teardown will be required, and higher initial costs will result for higher temperature materials.

Exhaust gas recirculation (EGR) and water injection are two effective control techniques that will require some development to overcome several operation and maintenance problems now being experienced. Exhaust gas recirculation requires new hardware components which will mandate new maintenance techniques. Problems of fouling the flow passages of the cooling heat exchanger, the engine turbocharger, and the aftercooler with particulate must be solved, or frequent engine teardown will be required. Under varying load conditions a sophisticated control system is required or the engine may stall or emit unacceptable smoke levels. Fuel consumption penalties with EGR are small.

Water injection can cause severe maintenance problems. Deposits from untreated water can build up on internal engine surfaces, and also foul the lubricating oil. The problem can lead to major engine maintenance requirements. Water injection also adds another system to the engine which must be maintained and controlled.

Although not demonstrated, combustion chamber modifications are expected to present the least impact to operation and maintenance.

Maintenance requirements can be expected to increase slightly if additional injectors, spark plugs, and valves are added to the chamber. However, because this control technique involves new design, many of the additional maintenance requirements can be designed out. Fuel penalties are expected to be small.

Catalytic reduction will require no additional engine maintenance, since it is a flue gas treatment technique, rather than an engine modification. However, operating the catalyst system may prove to be expensive. Fouling the catalytic surfaces with particulate may require frequent regeneration. The catalyst may also have a relatively short life and need to be replaced. Another system, ammonia injection, must be added and maintained for most applications, and the cost of ammonia must be included in engine operation. Finally, harmful products of the reaction may be produced if the catalyst temperature varies from the proper level, or if excessive ammonia is injected. The catalyst must be installed and operated on an engine before all these effects can be quantified.

4.4.3 Cost Impacts of Controls

Tables 4-21 through 4-24 compare the incremental costs of retard, air-to-fuel increase, and exhaust gas recirculation to those of an uncontrolled turbocharged engine. These tables show that ignition retard increases power costs 6 to 7 percent, air-to-fuel increase increases power costs 3 to 7 percent and EGR increases power costs 5 to 14 percent. Manifold air temperature reduction should only have a small cost impact, about a 1.5 percent increase in initial engine cost and an increase in the cost of power of about 1 percent. Derate is a viable technique only if spare power is available elsewhere. Though derating would increase fuel consumption and raise operating costs, specific figures are not presented here because of the difficulty in specifying highly site dependent costs.

In general, the incremental initial capital costs of the available controls range from 0 to 5 percent of an uncontrolled engine's cost. However, the total annualized cost to control can increase the cost of power from an engine by 1 to 14 percent, a significant impact due to additional fuel and maintenance requirements.

By combining control techniques, it may be possible to achieve the same NO_x reductions with a smaller fuel penalty, or reduce NO_x levels more than could be achieved by each technique alone. Table 4-25 compares

Table 4-21. Typical Costs for Uncontrolled Engines (1978 Dollars)

Parameters	Typical Engine			
	Diesel	Dual Fuel	Natural Gas	
	3000 kW (Electrical Generation)	3000 kW (Electrical Generation)	3000 kW (Gas Transport)	750 kW (Gas Production)
Initial Cost, $/kW	240	240	240	80
Capital Cost Factor	0.2	0.2	0.2	0.2
Operating Hours hr/yr	8,000	8,000	8,000	8,000
Maintenance, $/kW	0.005	0.005	0.005	0.005
Fuel cost, $/GJ	3.10	2.00	2.00	2.00
Fuel Consumption, kJ/kWh	9,900	9,200	9,900	11,300
Lubrication, % Fuel Cost	5	10	10	10
Annualized Costs ($/kWh)				
Capital	0.006	0.006	0.006	0.002
Maintenance	0.005	0.005	0.005	0.005
Fuel & Lubrication	0.032	0.020	0.022	0.025
Total	0.043	0.031	0.033	0.032

Table 4-22. Estimated Incremental Cost Due to Retard (1973 Dollars)

	Engine/Fuel Type			
	Diesel	Dual Fuel	Natural Gas	
	(Electrical Generation)	(Electrical Generation)	(Oil and Gas Pipeline)	(Oil and Gas Production)
Capital ($/kW)	0	0	0	0
Maintenance ($/kWh)	0.0016	0.0016	0.0016	0.0016
Fuel ($/kWh)	0.0012	0.0007	0.0008	0.0009
Total Annualized ($/kWh)[a]	0.003	0.002	0.002	0.002
Percent increase in initial cost	0	0	0	0
Percent increase in total annual past cost	7.0	6.4	6.1	6.2
Percent reduction in NO_x	20-30	20-30	20-30	20-30

[a] Assumes 8000 hours operating year.

Table 4-23. Estimated Incremental Cost of Air-to-Fuel Increase (1978 Dollars)

	Engine/Fuel Type			
	Diesel	Dual Fuel	Natural Gas	
	(Electrical Generation)	(Electrical Generation)	(Oil and Gas Pipeline)	(Oil and Gas Production)
Capital ($/kW)	0	0	0	0
Maintenance ($/kWh)	0.0002	0.0002	0.0002	0.0002
Fuel ($/kWh)	0.0031	0.0004	0.0004	0.0004
Total Annualized ($/kWh)[a]	0.003	0.001	0.001	0.001
Percent increase in initial cost	0	0	0	0
Percent increase in annual cost	7.0	3.0	3.0	3.0
Percent reduction in NO_x	20	40	40	40

[a] Assumes 8000 hours operating year.

Table 4-24. Estimated Incremental Cost of External Exhaust Gas Recirculation (1978 Dollars)

	Engine/Fuel Type			
	Diesel	Dual Fuel	Natural Gas	
	(Electrical Generation)	(Electrical Generation)	(Oil and Gas Pipeline)	(Oil and Gas Production)
Capital ($/kW)	12	12	12	4
Maintenance ($/kWh)	0.002	0.004	0.004	0.004
Fuel ($/kWh)	0	0	0	0
Total Annualized ($/kWh)[a]	0.0023	0.0043	0.0043	0.0041
Percent increase in initial cost	5	5	5	5
Percent increase in annual cost	5.3	14	14	13
Percent reduction in NO_x	20	20	20	20

[a] Assumes 8000 hours operating year.

Table 4-25. Estimated Incremental Cost of Combined Controls for Large Bore Diesel Engines at 40 Percent NO_x Reduction (1978)

	Control Technique		
	Retard	Air-to-Fuel Changes and Manifold Air Cooling	Air-to-Fuel and Retard
Capital ($/kW)	0	3.6	0
Maintenance ($/kWh)	0.0016	0.001	0.0018
Fuel ($/kWH)	0.0024	0.0015	0.0015
Total Annualized ($/kWh)[a]	0.0040	0.0026	0.0033
Percent increase in capital cost	0	1.5	0
Percent increase in annual cost	9.3	6.0	7.7
Percent reduction in NO_x	40	40	40

[a] Assumes 8000 hours operating year.

three different methods for reducing NO_x by 40 percent from a large bore diesel engine. For this case, there is a definite advantage to using combined controls since the two combined techniques, air-to-fuel ratio change and manifold air cooling, or air-to-fuel ratio change and retard, had a lower brake specific fuel consumption (BSFC) than retard alone.

Finally, Table 4-26 lists projected control requirements and costs associated with achievable control levels for typical diesel, natural gas, and dual fuel engines assumed to be turbocharged. In the case of natural gas and dual fuel engines, the obvious preferred approach from a cost-effectiveness view would be to go directly to the more stringent control level with air/fuel adjustments. It should be noted that all values in Table 4-26 are only typical ones and control levels may not be achievable for all engines.

4.4.4 Research and Development Trends

Currently available operational adjustment NO_x controls can only reduce emissions by approximately 40 percent, while significantly increasing operating cost and maintenance requirements. Advanced combustion chamber redesigns have the potential of achieving similar NO_x reductions but at lower cost and smaller fuel penalty. If very low NO_x emissions are required, catalytic exhaust gas treatment is the only developing technique with that potential.

There are two major weaknesses in the data base for combustion modification controls on IC engines. The information on operational effects and long-term durability of these control techniques could be more complete, especially combustion chamber redesign data and catalytic exhaust gas treatment. More information on combining these controls to achieve an optimum of low emissions and high efficiency is needed. Also the available data on emissions other than NO_x, CO, and total hydrocarbons are very limited. The amount and type of organics emitted from these large bore engines are not very well understood. The potential mutagenicity of organic emissions in diesel exhaust is of major concern.

Research is needed on designing a high efficiency low NO_x emitting engine. Even with the best available controls applied, the large bore stationary reciprocating internal combustion engine is the highest NO_x emitter on a heat input basis of all the major combustion sources.

Table 4-26. Projected Control Requirements for Alternate NO_x Emission Levels

Type	(g NO_x/kWh Output)	Control Techniques	(Mills/kWh Output)
Diesel	17	Baseline	--
	14	Exhaust gas recirculation	2.3
	12	Retard	2.8
	10	A/F increase + retard	3.3
Natural gas	15	Baseline	--
	12	Exhaust gas recirculation	4.3
	11	Retard	2.4
	9	A/F increase	1.0
Dual Fuel	11	Baseline	--
	9	Exhaust gas recirculation	4.3
	8	Retard	2.3
	7	A/F Increase	1.0

EPA is currently sponsoring several programs in the health effects area as well as new engine designs for low NO_x and high efficiency. These programs should help resolve many of the major data gaps in the operational and environmental impacts of NO_x controls.

4.5 RESIDENTIAL WARM AIR FURNACES

4.5.1 Status of Control Alternatives

Emission control technology for residential equipment is typically adapted to the specific fuel and burner type. Because NO_x emissions from either gas or distillate oil combustion are primarily due to thermal NO_x, control techniques are aimed at controlling temperature or oxygen availability in the high temperature flame region. Tables 4-27 and 4-28 summarize NO_x control alternatives for residential heaters firing natural gas and distillate oil respectively. These controls have been developed primarily for warm air furnaces; however, the advanced burner and combustor redesign technology presented in these tables could possibly be applied also to other domestic heating equipment as well as some larger commercial installations.

For residential gas-fired heaters, the American Gas Association (AGA) has developed radiant screens and secondary air baffles capable of average NO_x reductions of 58 and 20 percent respectively (References 4-22 through 4-24). However, these controls may find little application because of installation and performance problems highlighted by the Gas Appliance Manufacturer's Association (GAMA -- Reference 4-24). Two advanced NO_x control alternatives are the Bratko surface combustor and the Amana Heat Transfer Module (HTM -- References 4-22 and 4-25). In these concepts, radiation heat transfer from the combustion zone to the heat exchanger causes a low flame temperature and thus low NO_x production while achieving good efficiency and low CO levels. NO_x emissions from both the Bratko and Amana burners are approximately 20 percent of levels from conventional warm air furnaces. The Amana is the only commercially available unit at a cost to the consumer generally ranging from \$100 to \$300 above that of a conventional furnace.

The modulating furnace system produces a cooler flame by altering the burner firing rate to respond to heating costs instead of cycling on and off. NO_x reductions of about 40 percent have been reported. AGAL

Table 4-27. Performance Summary of Low NO_x Control Equipment for Natural Gas-Fired Residential Heaters

Control	Average Operating Excess Air (percent)	Cyclic Pollutant Emissions ng/J heat input			Steady State Efficiency (percent)	Cycle Efficiency (percent)	1978 Installed Control Cost	Comments
		NO_x	CO	UHC[b]				
Conventional Units	40-120	28-45	8.6-25	3.3-33	70	60-65	c	Costs include installation.
Radiant Screens	40-120	15-18	6.4	NA	75	70	NA	Emissions of CO and HC can increase significantly if screen is not placed properly or deforms.
Secondary Air Baffles	60-80	22	14	NA	NA	NA	NA	Requires careful installation. Best suited for single port upshot burners.
Surface Combustion Burner	10	7.5	5.5-9.6	NA	NA	NA	$100-$200	Not commercially available. Still under development.
Amana (HTM)	NA	7.7	26	NA	85	80	$100-$300 over conventional furnace	Commercially available design. Spark ignited thus requires no pilot.
Modulating Furnace	NA	25	NA	NA	75	70	$50-$250 over conventional furnace	Furnace is essentially derated. Thus it requires longer operation to deliver a given heat load. furnace
Pulse Combustor	NA	19-20	NA	NA	95	95	$300-$600	Currently being investigated by AGAL. Efficiencies correspond to flue gas condensing systems.
Catalytic Combustor	NA	<5	NA	NA	90	85	$150-$250	Still at the R&D stage. Efficiencies correspond to flue gas condensing systems.

[a] Sum of NO + NO_2 reported as NO_2
[b] Unburned hydrocarbons calculated as methane (CH_4)
[c] Typical costs of uncontrolled unit $500-$800
[d] NA = not available.

Table 4-28. Performance Summary of Low NO_x Control Equipment for Distillate Oil-Fired Residential Heaters

Control	Average Operating Excess air (percent)	Cyclic Pollutant Emissions ng/J heat input					Steady State Efficiency (percent)	Cycle Efficiency (percent)	1978 Installed Control Cost	Comments
		NO_x[a]	CO	UHC[b]	Smoke Number	Particulate				
Conventional Units	50-140	37-85	15-30	3.0-9.0	3.2	7.6-30	75	65-70	c	Range in NO_x emissions is for residential systems not equipped with flame retention burners
Flame Retention Burner Head	20-30	26-88	11-22	0.2-1.8	2.0	NA	80-83	NA	\$52[e]	If new burner is needed as well as a burner head, the total cost would be \$385. Cost is for 1978-79 heating season.
Controlled Mixing Burner Head by EPA/ Rocketdyne	10-50	34	13	0.7-1.0	Less than 1.0	NA	80	NA	\$43[e]	Cost of mass produced burner head only about \$1.50. Combustible emissions are relatively low because hot firebox was used.
Integrated Furnace System by EPA/ Rocketdyne	20-30	19	20	1.2	Less than 1.0	NA	84	74	\$250 over conventional furnace	Uses optimized burner head. For new furnace installation only. Combustible emissions are higher than with burner head because of quenching in air cooled firebox. Recent cost estimate.
Blueray "blue flame" Burner/Furnace System	20	10	4.5-7.5	1.5-2.5	zero	NA	84	74	\$100 over conventional furnace	New installation only. Furnace is commercially available. Recent cost estimate.
M.A.N. Burner	10-15	10-25	less than 30	NA	less than 1.0	NA	85	NA	NA	Both for retrofit or new installations. Not yet commercially available in U.S. Commercialization expected in 1980.

[a] Sum of NO and NO_2 reported as NO_2

[b] Unburned hydrocarbons calculated as methane (CH_4)

[c] Typical costs of uncontrolled unit \$650-\$1000

[d] NA = Not available.

[e] Original costs reported for years other than 1978 were corrected for inflection using Gross National Product (GNP) implicit price deflectors

is currently investigating pulse combustion for residential heating using a condensing exhaust gas system. Preliminary NO_x emissions have been reported in the 19 to 20 ng/J range (Reference 4-26). Commercialization of the pulse combustor residential heating system is expected in 1981 at the earliest. Catalysts promoting combustion of fuel at low temperature offer potential for very low NO_x emissions while maintaining good combustion efficiency (Reference 4-27). Research groups and trade organizations are investigating the commercial feasibility of catalytic combustion for residential warm air and hot water systems burning natural gas. Performance and emission data for these systems have not yet been published; however, NO_x emissions are expected to be very low.

Residential oil-fired heaters are forced draft fired and therefore more readily modified for reduced emission and increased efficiencies than natural draft gas-fired heaters. Early work involved the development of the flame retention oil burner (References 4-28 and 4-29). These units produce lower CO, UHC, and smoke emissions and operate at excess air levels lower than previous burner designs. In some particular designs the flame retention devices also lower NO_x emissions by 20 to 40 percent. Furthermore, they stay tuned longer and thus maintain low combustible emission levels. These units are now the most popular residential oil burners being sold.

Under an EPA sponsored program, Rocketdyne developed an optimized burner head for retrofit application on existing domestic oil-fired heaters (Reference 4-30). It was estimated that widespread application of the relatively inexpensive burner head device would be effective in reducing NO_x by 20 percent and increasing efficiency by 5 percent on the average for each retrofitted furnace. Recently the burner has been combined with an optimum low emission high efficiency warm air furnace (Reference 4-31). NO_x emissions have been reduced by 65 to 70 percent and steady state efficiencies have been increased by 10 percent. The EPA program emphasized the necessity to match the firebox, burner and heat exchanger design to achieve the optimum low NO_x condition while maintaining low levels of CO, UHC and smoke.

Both the Blueray "blue flame" furnace and the M.A.N. burner use aerodynamic flue gas recirculation to achieve a blue flame with distillate fuel oil. These burners thus achieve reduced flame temperature, dilution of the oxygen concentration in the near-burner zone and prevaporization of the fuel prior to ignition. These conditions result in very low NO_x emissions on the order of 10 to 15 ppm corrected to 0 percent excess air, representing NO_x reduction of 80 to 85 percent. Theoretically, these burner concepts could be scaled up to larger commercial sizes. The Blueray furnace is the only commercially available low NO_x system in the U.S. and thus represents the best available control technology for residential oil-fired equipment.

NO_x control technology for solid fuel-fired residential and commercial equipment is very limited. Past and ongoing test programs have mainly dealt with quantifying the pollutant levels and identifying equipment operating parameters and fuel characteristics which have some impact on these levels. Primary pollutants of interest for this category of equipment have been particulate and smoke emissions as well as levels of unburned hydrocarbons, toxic elements and polycyclic organic matter (POM). The simplicity of the solid fuel-fired equipment, whether coal- or wood-fired, often does not permit extensive modification of existing equipment or operating procedures to reduce NO_x levels. Investigative efforts in this area should continue to determine potential NO_x control technology applicable to new unit design while still concentrating on reducing the impact of other criteria and noncriteria pollutant emissions.

4.5.2 Process Impacts of Control

With the exception of the radiant screen and secondary air baffle concepts, the available control techniques for gas- and distillate oil-fired residential systems appear to be well developed and engineered burner and/or integrated furnace systems. No operational or maintenance problems are expected with these burner/furnace systems. Only the usual annual service tuning is recommended. Furthermore these systems generally tend to have higher cycle efficiencies as well as higher steady state efficiencies than conventional furnaces, as indicated in Tables 4-27 and 4-28.

The radiant screen and secondary air baffle devices suffer from high sensitivity of performance to geometry and positioning with respect to the burner port. Furthermore, the screens have questionable durability and may deform in the flame. The Gas Appliance Manufacturers' Association has cautioned against the use of these devices until further investigative efforts are completed (Reference 4-24).

4.5.3 Cost Impacts of Controls

Table 4-29 summarizes the cost data for the most effective NO_x control alternatives for residential heating systems. As indicated, retrofit of the optimized burner head for residential oil-fired warm air furnaces represents the most cost-effective alternative to achieve a NO_x emissions level of about 45 ng/J of useful heat. The payback periods listed are estimates based on the time required to recover the money spent for the initial investment of installing NO_x control equipment. Since all these control alternatives bring about an increase in thermal efficiency, and thus fuel savings, the initial investment cost is often recovered over a 1 year or less time period. Thus, taking into account the potential fuel savings, the adverse cost impact of controls (higher initial furnace cost) is minimal. Indeed, it appears that incorporation of these controls may be desirable purely from the viewpoint of energy conservation and cost savings.

4.5.4 Research and Development Trends

A substantial amount of information has been gathered on emissions from residential space heating equipment. In addition, numerous control alternatives for NO_x and combustible pollutants have also been investigated. Some low NO_x and high efficiency furnace designs are commercially available, while other equally effective designs are either at final demonstration stages or await commercialization. These designs will find wider application and more extensive performance data will become available as regulatory incentives appear. Performance tests on this improved heating equipment are being performed through EPA sponsored field and laboratory programs. These and other test programs will aid in further documenting the performance, reliability of these advanced controls and quantifying their impact on other pollutant emissions.

Table 4-29. Cost Impact of NO_x Control Alternatives

Control	Fuel	Achievable NO_x Level ng/J Useful Heat	1978 Incremental Investment Cost	Cost Effectiveness $/(ng/J)[a]	Payback Period Based on Annual Fuel Bill of $500
Amana (HTM) Furnace	Natural Gas	12 (390 ng/m^3gas)	$100-$300 over cost of conventional furnace	1.7-5.2	1-3 years
Modulating Furnace	Natural Gas	35 (920 ng/m^3 gas)	$50-$250 over cost of conventional furnace	1.4-7.0	1-3.8 years
Surface Combustion Burner (Infrared Bratko type)	Natural Gas	12 (39 ng/m^3 gas)	$100-$200 over cost of conventional furnace/ heater	1.7-3.4	3.5-8.0 years
Pulse Combustion Burner[b]	Natural Gas	21 (683 ng/m^3 gas)	$300-$600 over cost of conventional furnace/ heater	6.1-12.2	1.7-3.5 years
Catalytic Combustion Burner[b]	Natural Gas	Estimated 5 (163 ng/m^3 gas)	$150-$250 over cost of conventional furnace/ heater	2.3-3.9	1.4-2.3 years
Flame Retention Burner Head	Distillate Oil	50 (1.8 g/kg fuel)	$52 -- retrofit including installation	2.6	Less than 1 year
Flame Retention Burner	Distillate Oil	50 (1.8 g/kg fuel)	$385 -- retrofit of reduced capacity burner	12.8	3.5 years
EPA/Rocketdyne Burner Head	Distillate Oil	45 (1.6 g/kg fuel)	$43 -- retrofit including installation	1.3	Less than 1 year
EPA/Rocketdyne Furnace	Distillate Oil	29 (0.9 g/kg fuel)	$250 over cost of conventional furnace	4.2	2.5 years
Blueray Furnace	Distillate Oil	20 (0.7 g/kg fuel)	$100 over cost of conventional furnace	1.7	1 year

[a] Based on uncontrolled NO_x emissions of 70 ng/J heat output for natural gas-fired heaters and 80 ng/J heat output for distillate oil-fired heaters. Cost-effectiveness is based on the differential investment cost of the control.

[b] Based on installation on a condensing system where seasonal efficiencies can be as high as 95 percent.

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SECTION 5
PROJECTED COMBUSTION MODIFICATION REQUIREMENTS

One of the major goals of the NO_x EA program is to identify the most cost-effective, environmentally sound NO_x control techniques to attain and maintain ambient air quality standards to the year 2000, and, if adequate controls are unavailable, to recommend R&D priorities to develop needed technologies. A key aspect of satisfying this goal is to identify and incorporate into the analysis the effects or potential effects of existing and evolving regulatory strategies which could impact the need for NO_x controls. The primary purposes of this section are to summarize the current regulatory activities that will, or could potentially, affect the need for NO_x controls, to discuss the impacts of these activities, and to identify those combustion modification NO_x controls necessary to meet current and anticipated regulations. Current EPA activities and policy in these areas should be considered when assessing control needs.

In Section 5.1 the regulatory basis for NO_x control is reviewed with emphasis on the Clean Air Act (CAA) provisions which could or do necessitate increased NO_x control. Current and projected nonattainment for the annual average NO_2 standard and the resulting NO_x control requirements are discussed in Section 5.2. Projections discussed in this section were developed for the purpose of identifying control and control development needs and should not be construed as representing or directly influencing EPA regulatory policy. It is important to note that these projections are very sensitive to assumptions made with respect to energy use scenarios, emission factors, and control application scenarios. The projections discussed in section 5.2 are based on information available in 1979. Similar projections based on more recent information may be more reliable. Other issues, such as hydrocarbon control, acid precipitation, and visibility protection, which relate to the need for NO_x control are briefly discussed in Section 5.3.

5.1 REGULATORY BASIS FOR NO_x CONTROL

The CAA provides the basic framework for control of new and existing sources. The key regulations and the corresponding control level definitions impacting NO_x control requirements include:

- National Ambient Air Quality Standards (NAAQS's) regulating ambient levels of NO_2 and ozone
- State Implementation Plan (SIP) regulations on new and existing sources for attainment or maintenance (LAER, RACT, BACT)*
- New Source Performance Standards (NSPS) for the major sources of NO_x emissions
- Nonattainment New Source Review (NSR) rules including regulating emissions from new sources (LAER)* and offsets for those emissions
- Prevention of Significant Deterioration (PSD) requirements on controls for new sources in attainment areas (BACT)*
- Visibility protection regulations controlling emissions from new and existing sources in Class I regions (BACT, BART)*

Table 5-1 summarizes these regulations, giving the regulatory objective, implementation mechanism, basis for the control technology, and the current status of each. The specific control levels or technologies required for RACT, BACT, and BART are left to the discretion of the states. The definition of LAER, however, includes the most stringent emission limitation which is achieved in practice or contained in any SIP. Thus, the application of advanced control technologies, such as ammonia injection or selective catalytic reduction as are being required in Los Angeles, could establish these levels of control as LAER for similar new sources in all NO_2 nonattainment areas.

In this study the most attention has been given to control requirements for attainment or maintenance of the existing annual average

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*LAER: Lowest Achievable Emission Rate
BACT: Best Available Control Technology
BART: Best Available Retrofit Technology
RACT: Reasonably Available Control Technology (LAER and BACT are as a minimum at least as stringent as NSPS)

Table 5-1. Summary of Environmental Regulations Potentially Affecting NO_x Control Implementation

Regulatory Objective	Type of Standard	Implementation Mechanism	Control Technology Basis	Status of Projections
Attain Annual National Ambient Air Quality Standard (NAAQS)	Existing source emission limit CAA §110	State Implementation Plan (SIP) for non-attaining AQCR's	Reasonably Achievable Control Technology (RACT) or lower as defined by states	Rule 1135.1 in SCAQMD. Other nonattainment regions not currently requiring retrofits[a]; anticipate regulations in SCAQMD on refinery heaters, I.C. engines, home furnaces, and industrial boilers and regulation in other regions to compensate for source growth; RACT guidelines published by EPA.
	New Source Review emission limit CAA §129,173	State Implementation Plan (SIP)	Lowest Achievable Emission Rate (LAER)	Case by case determinations made based on most stringent demonstrated technologies; few LAER determinations made; guidelines in preparation. Several areas of California require stringent NO_x controls as part of NSR.
	Emission offset of existing sources CAA §129,173	State Implementation Plan (SIP)	At discretion of source owners	NO_x offsets in NO_2 nonattainment areas; limited use in CA for hydrocarbon offsets in oxidant nonattainment areas; Offset Policy still being formulated.
Maintain Annual National Ambient Air Quality Standard (NAAQS)	Emission regulations on new or existing sources CAA §110	State Implementation Plan (SIP) for designated Air Quality Maintenance Areas to avoid NAAQS violation due to growth	At discretion of state governments in Air Quality Maintenance Plans	Few controls currently required in areas outside California; expanded control projected in 1980's to compensate for growth; see Appendix C.

[a] Other areas have implemented retrofit controls as part of state or local standards not directly tied to nonattainment SIPS; San Diego is considering a rule similar to 1135.1 depending on the SCAQMD experience and the prospects for achieving attainment by controls on other sources.

Table 5-1. Concluded

Regulatory Objective	Type of Standard	Implementation Mechanism	Control Technology Basis	Status of Projections
Prevention of Significant Deterioration	New source emission regulation CAA §160-169	Preconstruction and premodification permit program	Best Available Control Technology (BACT) or lower	Case by case BACT determinations will be made after promulgation in 1980; must be NSPS or lower.
Visibility Protection	Existing major stationary source; CAA §165,169A	USEPA regulations and State Implementation Plans (SIP's)	Best Available Retrofit Technology (BART)	Regulations promulgated, 12/80; definition of BART determination process by EPA.
Compensate for Source Growth	New source performance standards (NSPS); CAA §111	USEPA nationwide control of new sources	Best demonstrated technology	Utility boilers standard set 1971; revision promulgated 1979. Industrial boilers to be proposed 1982 at earliest.
	State and local emission limit of existing sources	Statewide or local through AQMD's	At discretion of state and local governments	Many regulations in effect which cover more source types or which have a more stringent limitation on new sources; many regulations in effect on existing sources; enforcement is spotty.

standard. Results (control requirements) are discussed in detail in Section 5.2. The Prevention of Significant Deterioration policy (maintenance) and the Nonattainment policy (attainment) are briefly discussed in the remainder of this section.

5.1.1 Prevention of Significant Deterioration

Prevention of Significant Deterioration provisions (Sections 160 through 169 of the CAA) are designed to protect air quality in areas now meeting ambient standards. PSD regulations perform three interrelated functions: (1) they limit the degradation of air quality in "clean air" areas; (2) they provide a mechanism to regulate pollutant emissions from new and modified sources; and (3) they allow the individual states to determine the degree of new source growth to be allowed in clean air areas.

The PSD provisions outlined in the CAA allow for three area classification categories for SO_2 and particulate: Class I, where practically any air quality deterioration would be precluded; Class II, where deterioration in air quality arising from moderate growth would not be considered significant; and Class III, where intensive and concentrated industrial growth can occur while not departing from the intent of the PSD regulations. The area classification plans are to be executed and enforced through revised SIPs.

Specific ambient pollutant increment concentrations for SO_2 and particulate are assigned to each classification category which, when added to the determined "baseline" pollutant concentrations in a given area, prescribe the maximum allowable air quality degradation for that area. The number of new sources or expansions allowed in a given area are regulated through the preconstruction permitting process. This process requires a new source to demonstrate its strategy for compliance with the PSD increments, and, among a number of specific stipulations, requires new sources to employ "best available control technology" (BACT). As defined by the CAA, BACT means an emission limitation based on the maximum degree of pollutant reduction available, taking into account energy, environmental, economic, and other costs. In no event can BACT mean an emission limitation less stringent than that allowed under the NSPS for a particular source. The most important aspect of BACT is that it can be determined on a case by case basis.

The Clean Air Act stipulated that sulfur dioxide (SO_2) and particulates will be presently covered by PSD regulations within SIP's. The Act also required the application of BACT to sources emitting "significant" amounts of other regulated pollutants. By mid-1981 the EPA had conducted a study to determine whether and how other pollutants are also to be covered by PSD beyond the BACT requirements. The pollutants studied include nitrogen oxides, hydrocarbons, carbon monoxide, and ozone. The regulations, when promulgated, must provide specific measures beyond BACT at least as effective as the increments established for SO_2 and particulates. Such measures may include air quality increments and specific numerical measures against which permit applications may be evaluated.

Changes to PSD rules have had significant impact on NO_x control requirements. These changes include:

- Redefining the "potential to emit" so that potential emissions consider air pollution control equipment. Potential emissions were previously based on uncontrolled emissions. This will reduce the number of new facilities subject to PSD rules. This new definition will also apply to New Source Review in nonattainment areas.
- Redefining "major modification" to apply to the net increase in emissions from the source thereby allowing contemporaneous emission decreases at a source to offset increases
- Requiring BACT for all pollutants for which major construction would create significant net emissions increases. (For NO_x, 36.4 Mg/yr, 40 tons/yr, is considered significant).

The type and level of control established under BACT can vary according to different regions, since it is a case by case determination allowing states to choose the amount of new source growth desired. In essence then, the implications of any PSD NO_2 regulations are economical since they concern the cost of controlling new sources in a region so as to ensure compliance with an established level of NO_2 ambient degradation. Unfortunately, it is difficult to predict the regional impacts of an NO_2 PSD regulation since: (1) the exact form of a NO_2 PSD regulation is not known (i.e., allowable ambient increment or emissions limitation), and (2) the nature of BACT and the amount of local growth desired cannot be assumed.

5.1.2 The Nonattainment Policy

The nonattainment provisions of the Clean Air Act Amendments of 1977 outline regulations governing the introduction of new sources in regions which have been shown by monitoring data (or calculated by air quality modeling) to exceed any national ambient air quality standard. Under the CAA, revised SIP's for these regions must assure attainment of primary air quality standards for NO_x and the other criteria pollutants no later than December 31, 1982; with respect to especially severe ozone and carbon monoxide problems, the deadline may be extended to December 31, 1987.

Since July 1, 1979, the State must have a revised and approved implementation plan, assuring attainment as a precondition for the construction or modification of any major stationary source. This plan must include a permitting process for construction or modification of major stationary sources in nonattainment areas. A permit may only be granted if the following conditions are met:*

- Total emissions in the proposed modification/construction area must be significantly less after the modified or new facility is in operation, than before
- The proposed source is in compliance with LAER
- The owner or operator of the proposed new or modified source has demonstrated that all major stationary sources owned or operated by such person in such state are in compliance, or on a schedule for compliance with all applicable emission limitations and standards under the Act.

The most stringent new source review requirements for NO_x are in California, where NO_x is considered a precursor to NO_2, ozone, particulate, and visibility impairment.

The implications of the nonattainment policy, much like those arising from PSD, primarily concern the economics of facility siting and operation. Unlike PSD, which governs pollutants in areas now meeting ambient standards, the nonattainment provisions cover mechanisms designed to ensure attainment in those areas violating standards with regard to a particular pollutant. To progress toward attainment, the nonattainment provisions stipulate that emissions from existing sources be reduced accordingly. If new sources are to be added in the region, the nonattainment provisions require that emissions from existing sources be reduced so that resulting total emissions represent progress toward attainment, and that new sources meet very strict emission limitations, essentially regardless of the cost.

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*Federal Register, May 13, 1980: 45FR31307-31312, and August 7, 1980: 45FR52676-52748.

In the following section the specific NO_x control activities which may be required to comply with these regulations are discussed.

5.2 ANNUAL AVERAGE STANDARD

The present ambient air quality standard for NO_2 (100 μg/m^3, annual average) was promulgated in April 1971. There were, in 1981, six counties or portions of counties that have been declared nonattainment for NO_2 -- four counties in the Los Angeles area, Cook County, Illinois, and Denver County, Colorado.* The last two are borderline in their exceedance of the standard. The actual number of counties exceeding the standard could be much greater, since many areas do not have sufficient data on NO_2 ambient levels. Table 5-2 shows 15 metropolitan areas that can be considered as potential future violators of the annual average standard. Other estimates (References 5-1 and 5-2) extend this number to 34 if sufficient ambient data were available.

5.2.1 Methodology for Analysis of Control Needs

The NO_x control requirements to attain or maintain the annual average standard now and through the year 2000 have been assessed using the methodology described in References 5-2 and 5-3. The basic elements of that methodology are:

- Identify potential problem areas (AQCR's)* using 1974-1978 ambient data. Use 80 μg/m^3 as a lower limit of concern and give more significance to the most recent data.
- Select from the candidate areas a representative sample; consider emission source distribution (percent mobile, percent coal-fired power plants, etc.) and ambient level

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*San Diego County, California, was redesignated attainment for NO_2 in 1981.

Table 5-2. Potential NO_2 Problem Areas

AQCR[a]	AQCR Number	Maximum Annual Average ($\mu g/m^3$)[b]	
		1977	1978
Phoenix	015	96	114[c]
Memphis	018	98	95[c]
Los Angeles	024	161	160[c]
San Diego	029	94	--
San Francisco	030	91	83
Denver	036	97	92
Springfield, MA	042	96	84
New York City	043	85	84
Philadelphia	045	98	103
Chicago	067	136	119
Cincinnati	079	89	95
Providence	120	80	95
Detroit	123	124	106[c]
Cleveland	174	86	99
Houston	216	88	95

[a] AQCR (Air Quality Control Regions) were used as convenient geographical areas since both ambient data and emissions data were available by this designation at the time of this study. However, nonattainment designations would be applied to much smaller geographical areas -- counties or portions of counties.

[b] Based on reported valid annual average unless otherwise noted.

[c] Insufficient data for valid annual average; estimate based on best available data.

- Develop stationary source growth projections
- Develop mobile sources growth and control scenarios
- Use the most recent NO_x control cost and effectiveness data to rank stationary source controls according to least cost per incremental reduction in ambient concentration
- Apply growth scenarios to each area to project future year uncontrolled emissions
- Use a control application model to apply the necessary NO_x control in future years to maintain the standard. (This model applies controls in the most cost-effective manner and relates emissions to air quality using source weighted rollback.)
- Use the results from the model to assess NO_x control needs in future years

The most recent analysis, reported here, considered 10 of the areas listed in Table 5-2. These were selected to represent a variety of source category, fuel use, and mobile/stationary source mixes. Over 10 different emissions growth/source weighting combinations were considered for each area. Key elements of these scenarios are given below:

Stationary Source Growth

The three stationary source growth scenarios are described in Appendix C. Descriptive features for each scenario are given below:

- Conservation
    - Lowest total fuel consumption of the three scenarios
    - Based on provisions of National Energy Act
    - Emphasis on coal in utility and industrial sector
- High nuclear
    - Electrical generation grows at 5 to 6 percent per year
    - Increased electrification

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*AQCR (Air Quality Control Regions) were used as convenient geographical areas since both ambient data and emissions data were available by this designation at the time of this study. However, nonattainment designations would be applied to much smaller geographical areas -- counties or portions of counties.

  - Slightly more coal use than conservation case
  - Approximately 10 percent more fuel use in each sector than in conservation case
- Low Nuclear
  - Overall growth same as high nuclear
  - No new nuclear after 1985
  - Heavy emphasis on utility coal

As a result of applying these scenarios, stationary source NO_x emissions increased by 10 to 15 percent (relative to 1976 emissions) in 1985 and 30 to 90 percent in 2000, with the assumption of current and likely NSPS. The emphasis on coal is very significant, particularly with regard to the increase in uncontrolled emissions, and to control requirements.

Mobile Source Growth/Control

Emissions from mobile sources were calculated using the methods and emission factor data of Reference 5-4. It was found that one of the most significant factors influencing future year emissions was the control device deterioration factor. For example, a 50 percent reduction in deterioration factor for a 0.62 g/km (1.0 g/mi) standard reduced emissions more than going to a 0.25 g/km (0.4 g/mi) standard with the projected deterioration rates. Such an improvement is within the capacity of an effective inspection and maintenance (I/M) program.

The three mobile scenarios are described below:

- Low growth
  - Approximately 1 percent/year increase in vehicle population (i.e., following urban population growth)
  - 0.25 g/km light duty vehicle (LDV) standard
  - An effective I/M program reducing deterioration by 50 percent
  - Control of other categories as required by existing emission reduction schedules
- Medium growth
  - Approximately 3 percent/year increase in vehicle population (i.e., following historical patterns)
  - 0.62 g/km LDV standard

  - An effective I/M program reducing deterioration by 50 percent
  - Control of other categories as required by existing emission reduction schedules
- High growth
  - Same as medium growth except no I/M program

As a result of these scenarios mobile source emissions decrease 12 to 25 percent in 1985 and 3 to 50 percent in the year 2000. However, this may prove optimistic in light of recent legislation introduced to the House of Representatives proposing a relaxation of mobile NO_x standards from 0.62 g/km (1.0 g/mi) to 1.24 g/km (2.0 g/mi). If this legislation were to pass, the impact analysis performed by forty-one state agencies and additional local agencies indicate increasing nonattainment in many areas across the country. More specifically, this relaxation will (Reference 5-5):

- Increase total NO_x loadings by 16 percent in 1987 and by 39 percent in 2000
- Eight new areas could become nonattainment for NO_2 after 1982
- Eleven to fourteen areas could face the need for additional stationary NO_x control to reach and attain NO_2 attainment

This scenario was not considered in the present study.

The three mobile scenarios considered here were combined with the corresponding (low, medium, high) stationary scenarios to give a range of possible emissions growth projections from which to assess stationary source control needs.

5.2.2 Results

The results discussed in this section are based on information available in 1979. Projections based on more recent information may be more reliable. In addition, results discussed in this section should not be construed as reflecting or influencing EPA regulatory policy.

Using the projected emissions growth and 1977 ambient data, it is estimated that 20 metropolitan areas will need stationary source control beyond expected NSPS before the year 2000. This number could easily double if the deficiencies of the ambient monitoring system (assumed by Reference 5-1) are real. The results of the analysis indicate that areas (AQCR's) with 1977 annual averages greater than 80 $\mu g/m^3$ will need some form of control for stationary sources by 2000. Those areas with less than 40 percent mobile source emissions and large coal-fired power plant and industrial components will need the most control. In some cases, areas with 1977 levels as low as 70 $\mu g/m^3$ will need control. In the near-term (1985) a decline in mobile source emissions counteracts a small increase in stationary source emissions resulting in little net change in the annual average air quality for most areas evaluated.

The NO_x controls considered include combustion modifications (low excess air, staged combustion, and new burner, furnace and combustor designs), ammonia injection, and selective catalytic reduction (SCR). Evaluation of the control costs include capital costs, operating and maintenance costs, and fuel penalty. A generalized description of controls in order of least cost increment per unit of emissions reduction is shown in Table 5-3. In the analysis of specific areas, 30 distinct source/fuel type categories and 59 different controls were considered.

The specific level of control required in any area depends on the source mix, current ambient level, and growth scenario under consideration. Results for control levels in the year 2000 for those areas considered in this analysis are shown in Table 5-4. Included in this table are the relevant source mix data, base year ambient level, and control level for the high and low growth scenarios. Also shown in the table is the level of power plant control required if the ground level impact of utility boiler emissions is significantly reduced by the dispersion effects of high stacks. In these cases, as well as those with few power plant emissions, future air quality is more dependent on mobile source emissions growth, and utility NO_x controls are not as effective in improving air quality, thereby necessitating a greater level of control.

In the high growth cases, most of the areas studied need combustion modifications or ammonia injection by the year 2000. In the low growth cases, only those areas with a high percentage (~25) of emissions from coal-fired power plants need additional control. This is because the low growth case places a heavy emphasis on increased use of coal, which offsets the greatly reduced mobile source emissions.

Of particular interest is the impact of advanced low NO_x burners and advanced designs for coal-fired utility boilers. It was assumed that these

Table 5-3. Ranking of NO_x Controls (Most Cost-Effective First)

1	New warm air furnace designs
2	Low excess air for utility and industrial watertube boilers
3	Staged combustion for utility and industrial watertube boilers
4	Low NO_x burners
5	Advanced low NO_x burners and advanced designs for coal-fired utility boilers
6	IC engine and gas turbine controls
7	Combustion modifications for firetube boilers
8	Ammonia injection for utility and large industrial boilers
9	Selective catalytic reduction

Table 5-4. Control Requirements in the Year 2000 for Attainment of 100 μg/m^3 Annual Average NO_2 Standard

						Control Level[e]		
Area	No.	Base[a] Year μg/m^3	Percent[b] Mobile	Percent[b] Utility	Percent Utility Coal	High Growth	Low Growth	Power Plants at 20% impact[c] (High Growth)
Memphis	018	95	58	30	28	3	2[d]	2[d]
San Diego	029	105	63	25	0	3	0	V
Denver	036	97	49	34	24	3	2[d]	2[d]
Springfield, MA	042	90	57	14	0	1	0	1
New York City	043	85	51	23	2	2[d]	0	1
Philadelphia	045	100	55	21	8	3	0	4
Chicago	067	90[e]	37	29	26	2[d]	1	2[d]
Cincinnati	079	90	52	26	26	2[d]	2[d]	2[d]
Boston	119	86	46	28	0	2[d]	0	1
Detroit	123	100	53	30	20	3	2[d]	3
Cleveland	174	85	38	28	27	2[d]	2[d]	2[d]

[a] Base year ambient level based on composite of 1976 and 1977 ambient data.

[b] Relative to 1976 emissions.

[c] Assumes that power plant emissions have reduced ground level impact because of high stacks.

[d] Will require ammonia injection if advanced designs not developed and deployed in the late 1980's or early 1990's.

[e] Actual value for Chicago exceeds 100; this value used as a sensitivity test.

0 - No control beyond NSPS
1 - Low excess air
2 - Advanced combustion modification
3 - Ammonia injection
4 - Selective catalytic reduction
V - Violation

NO_x controls would be available in the mid 1980's and would be capable of meeting emission levels of 86 and 60 ng/J respectively. Their successful development is very important in determining the type of control and costs necessary to maintain air quality in those areas with significant coal utilization. Without the timely development and deployment of these controls or if the low levels are not achieved, ammonia injection and selective catalytic reduction will be necessary to achieve the same level of reduction. A conservative estimate is that 10 to 15 areas (counties or portions of counties) will need either the advanced designs (with emission levels of 86 ng/J) or ammonia injection or selective catalytic reduction by the year 2000.

Although the three growth scenarios result in approximately 50 percent difference in uncontrolled emissions, the major difference in control requirements is not so much in the type of control (i.e., low NO_x burner or OSC) but in the year in which it is necessary to apply that control and the amount of control needed by the year 2000.

5.3 OTHER CONSIDERATIONS

Several other provisions of the CAA or developments in knowledge of pollutant impact may have implications on the need for NO_x control. Among these are acid precipitation, visibility protection, PSD, and NO_x/HC interaction. Brief comments on each of these are given below.

Acid Precipitation

The EPA is conducting continuing studies on acid precipitation. Primary emphasis is expected to be on the formation mechanisms, monitoring and data collection, effects, and modeling. Acid precipitation, which is primarily formed from SO_x and NO_x emissions, poses a threat to crops, fish, trees, soil fertility, and structures. It has been most prevalent in the Northeast, but there is growing evidence of significant impact in the Midwest, Southeast, and West Coast.

The need for NO_x control to address the acid precipitation problem has not been resolved. If it is required, the most likely impact on NO_x control requirements would seem to be the need for increased control of utility and large industrial boilers, since the major source of acid precipitation precursors seems to be emissions from high stacks. This impact could be particularly severe for coal-fired boilers. Determination of control requirements will, however, await a better understanding of the role of NO_x in the formation of acid precipitation. Some analyses have suggested that local sources of sulfate and NO_x may play a much more important role in acid precipitation than previously thought.

Visibility Protection

The primary concern here is for protection of visibility in Class I areas, of which 158 have been identified. Both NO_2 and nitrate aerosols can contribute to visibility degradation within 40 to 50 km of a stack; however, their effects can be dominated by those of particulates and other aerosols in a relatively dirty plume. An EPA report to Congress on visibility protection was completed in November 1979; and regulations were promulgated in December 1980.

The major impact on new sources will be for plant siting. For existing sources, the problem is one of determining if a problem exists and to what extent each source contributes to the problem. Once resolved, contributing sources will be required to install BART. It is expected that, if required, BART will be limited to combustion modifications for NO_x control.

Prevention of Significant Deterioration

As previously stated, PSD increments for NO_2 have not been established, therefore it is difficult to establish the type and level of NO_x control requirements. BACT determination will be on a case-by-case basis allowing states to choose the amount of new source growth desired and the level of NO_2 ambient degradation. However, simple Gaussion dispersion models and NO_x to NO_2 conversion ratios, such as those in Reference 5-6, can be used to estimate maximum NO_2 ground level impacts. These can be compared to PSD increments, once established, to estimate NO_x control requirements.

The NO_x-HC Relationship

The interrelationship of NO_x and HC emissions in affecting NO_2 and ozone ambient concentrations is a well known fact. Smog chambers and analytical photochemical models have been used to study the chemistry of the NO_x-HC system. The necessity to consider this connection in the evaluation of control strategies has been recognized by EPA and is contained in the isopleth method for assessment of control needs for meeting ambient zone levels (Reference 5-7).

It is now clear that any control strategy for one of these pollutants must consider the consequent impact on ambient levels of both NO_2 and ozone. This is made more complex because the impact depends on the existing ambient concentrations, the spatial scale of interest, and the time duration of interest. For example, control measures to maximize improvement in urban NO_2 may result in an increase in rural (downwind) ozone levels. As another example, control strategies to reduce 1 hour peak concentrations may only shift the occurrence of the peak (in time or space) or may reduce the peak but have no effect on the annual average. Extensive studies of the ozone problem in the San Francisco area (Reference 5-8), the Los Angeles area (Reference 5-9) and the Denver area (Reference 5-10) have shown the detrimental effects of NO_x control on attainment of ambient ozone goals. However, it is also recognized that current, or future, violations of NO_2 standards must be anticipated.

The Empirical Kinetic Modeling Approach (EKMA, Reference 5-7) and the isopleth method have been extended to investigate the dependence of ambient NO_2 on NO_x and HC precursors. Application of the isopleth model (as described in Reference 5-11) to produce NO_2 isopleths was reported in Reference 5-12. The response of ambient NO_2 to changes in NO_x and HC precursors was found to fall into three distinct zones. In two of these, NO_2 is relatively insensitive to precursor HC; whereas in the third, the dependence is quite strong. Observed urban precursor levels suggest that most cities are in one of the HC insensitive zones. However, in colder seasons or in localized regions of low HC emissions (such as industrial plumes) NO_2 levels can be very sensitive to HC precursor levels. In a study of San Francisco using the Livermore Regional Air Quality Model (LIRAQ), NO_2 peaks were reduced 25 to 40 percent for a 50 percent reduction in HC (Reference 5-13). However, little impact on the NO_2 annual average was observed. Thus, HC control as a means of reducing short-term NO_2 peaks must be considered. Generally, it appears that the best approach will be simultaneous control of both NO_x and HC with the particular mix being determined by specific local conditions.

5.4 SUMMARY

In this section NO_x control requirements resulting from the current annual average NO_2 standard and several other aspects of the Clean Air Act have been discussed. The main points and major conclusions of the discussion are as follows:

- Six counties are presently in nonattainment with respect to the 100 μg/m^3 annual average standard, based on current monitoring data. It is estimated that 30 more areas would be in violation if sufficient monitoring data were available.
- The current monitoring network reflects the impact of area sources and, even so, does not adequately measure the extent of violation of the annual average
- Approximately 20 metropolitan areas will need stationary source control beyond expected NSPS before the year 2000 to stay below 100 μg/m^3 annual average. This number could double depending on the current extent of deficiencies in the monitoring network.
- Ten to fifteen metropolitan areas will need either advanced design combustion modification or ammonia injection and perhaps SCR by the year 2000 to stay below 100 μg/m^3 annual average
- The number of counties in violation of annual average standards will probably decrease in the near-term (1980 to 1990) but increase in the long-term (2000) without additional stationary source control beyond current and projected NSPS
- The role of NO_x in the formation of ozone and other photochemical oxidants is under continuing study and could result in additional NO_x control requirements
- The role of NO_x in acid precipitation is also under continuing study and could result in additional NO_x control requirements
- The major impact of the visibility protection requirements of the CAA will be on new source siting

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SECTION 6

ENVIRONMENTAL ASSESSMENT OF STATIONARY COMBUSTION SOURCES AND COMBUSTION MODIFICATION CONTROLS

As noted in Section 1, the goals of NO_x EA were to assess the environmental impact of stationary combustion sources and of combustion modification controls applied to these sources; and to identify the most cost-effective, environmentally sound combustion modification techniques to meet current and projected NO_2 ambient air quality goals. Addressing these goals requires:

- Ranking stationary combustion sources according to:
  - -- Their contribution to ambient NO_x levels
  - -- Their overall potential adverse environmental impact

  and thereby identifying the most significant opportunities for reducing NO_x while keeping overall environmental impact acceptable
- Identifying current and emerging combustion modification control methods and ranking these according to:
  - -- NO_x removal effectiveness
  - -- Cost
  - -- Process operational impacts
- Identifying expected regulatory requirements, identifying control strategies capable of meeting these nationwide, noting cases where current and emerging combustion modification controls are insufficient, and recommending Research and Development needs to address these insufficiencies
- Identifying other potentially hazardous combustion generated pollutants and evaluating the effects of combustion modification control on emission levels of these pollutants

Results of the NO_x EA in evaluating current and emerging combustion modification control techniques were presented in Section 4. Section 5 projected regulatory requirements, surveyed control needs in selected Air Quality Control Regions to meet these requirements, and identified potential problem areas. Section 3 discussed results of the pollutant impact severity analyses applied to field data on the selected NO_x control methods tested in terms of identifying potentially hazardous combustion generated pollutants and the effects of the controls tested on emission levels of these. This section ties these discussions together to form the NO_x EA program results in addressing the above stated program goals.

Specifically, Section 6.1 discusses results of stationary source potential impact rankings based on NO_x emission levels, emissions projections, and an estimated ambient impact based on NO_x emissions as well as flue gas multipollutant emissions. From Section 6.1, the priority sources for NO_x control are identified. Section 6.2 presents the preferred means of controlling specific source categories for NO_x to certain control levels, and, together with Section 6.1, presents preferred control strategies for meeting regulatory needs. From Section 6.2, the source/control priorities for controlling NO_x to meet current and projected ambient air quality standards are identified, and R&D needs to address deficiencies are noted. Section 6.3 flags other combustion generated pollutants of concern, assesses the effects of the priority NO_x controls on these, and concludes on the environmental soundness of combustion modification controls.

6.1 STATIONARY SOURCE PRIORITIES

Section 5 presented the regulatory basis defining the need for stationary source NO_x control and discussed the NO_x EA results projecting the kinds of sources needing NO_x controls to satisfy the current and projected regulatory mandates. These conclusions are reiterated as follows:

- Annual Average NO_2 Standard -- By the year 2000 many regions of the nation will require NO_x control application beyond that mandated by the relatively aggressive progression of New Source Performance Standards (NSPS) assumed in the analysis (see Appendix C). Retrofit of current technology combustion modifications at the least will be required. Many regions will require the advanced design controls currently under development; and possibly more stringent control, including selective catalytic reduction (SCR). Large point sources (coal-fired utility and industrial boilers) contribute most heavily to high annual average NO_2 levels, thus control of these will need emphasis.

- Short-Term NO_2 Standard -- Area sources (including mobile sources) contribute more heavily to high short-term NO_2 levels, though the impact of point source emissions is still quite significant. Since substantial further control of mobile source emissions is unlikely, projected violations of several possible levels of a short-term standard may require retrofit control of virtually all stationary source categories.
- Prevention of Significant Deterioration -- New point sources may require very stringent NO_x control in many regions
- Nonattainment -- Stringent new point source control, requiring NO_x emission levels as low as those attainable with SCR, will be needed in many regions. In addition, retrofit controls, with emphasis on large point sources, will be required.
- Acid Rain -- Stringent control of large point sources may be mandated in some areas

In summary, Section 5 results suggest that advanced control of virtually all stationary source categories, often to levels currently achievable only with current combustion modification technology combined with SCR, will likely be required in many regions of the nation by the year 2000. However, except for potential short-term standard considerations, control of large point sources, specifically coal- and oil-fired utility and industrial boilers, will be emphasized.

This view is substantiated by NO_x emissions inventory and projection results. Appendix B outlines the methodology used and the results obtained in compiling a multipollutant flue gas emissions inventory for 1977. Of particular interest is the source ranking for NO_x emissions. Table 6-1 summarizes these Appendix B results and shows the 15 largest contributors to NO_x emissions in 1977. The table shows that large coal-fired utility boilers dominate the ranking. Six of the 15 most significant sources fall in this category. Interestingly, gas-fired spark ignition internal combustion (IC) engines, and medium sized oil-fired

Table 6-1. NO_x[a] Mass Emission Ranking of Stationary Combustion Equipment for 1977

Rank	Sector	Equipment Types	Fuel	Annual NO_x (Gg)	Cumulative (Gg)	Cumulative[d] (percent)
1	Utility boilers	Tangential	Coal	1422.3	1422.3	13.5
2	Utility boilers	Cyclone furnace	Coal	924.6	2346.9	22.3
3	Reciprocating IC engines	75 kW to 75 kW/cyl[b]	Gas	790.4	3137.3	29.8
4	Utility boilers	Wall firing (dry)	Coal	736.4	3873.7	36.8
5	Utility boilers	Wall firing (wet)	Coal	717.9	4591.6	43.6
6	Reciprocating IC engines	>75 kW/cyl	Gas	702.9	5294.5	50.3
7	Utility boilers	Opposed wall (dry)	Coal	375.5	5670.0	53.9
8	Utility boilers	Wall firing	Oil	263.2	5933.2	56.4
9	Utility boilers	Wall firing	Gas	209.1	6142.3	58.4
10	Reciprocating IC engines	75 kW to 75 kW/cyl	Oil[c]	209.1	6351.4	60.4
11	Utility Boilers	Opposed wall (wet)	Coal	206.4	6557.8	62.4
12	Utility boilers	Tangential	Oil	164.5	6772.3	64.0
13	Utility Boilers	Opposed wall	Gas	162.4	6884.7	65.5
14	Reciprocating IC engines	<75 kW	Gas	124.6	7009.3	66.7
15	Industrial boilers	Cast iron boilers	Oil	108.3	7117.6	67.7

[a] NO_2 basis

[b] Power output

[c] Includes both distillate oil and gasoline

[d] Based on percent of total stationary source NO_x emissions

compression ignition engines also rank quite high. The significance of coal-fired sources is projected to increase in the future.

Appendix C outlines the energy use and emission factor (based on a relatively aggressive progression of NSPS promulgations) scenarios formulated to allow projecting NO_x emissions to the year 2000, and discusses results of these projections. Table 6-2 summarizes the results of Appendix C for the Conservation Scenario (based on the 1979 National Energy Act) in terms of ranking the projected 15 most significant NO_x sources in the year 2000. This table shows that coal-fired utility boilers will be the five highest emitters in the year 2000. Further, coal-fired industrial sources (small industrial stokers and large tangential units) appear high in the ranking, IC engines remain in the top 15, but their ranking decreases from 1977. Industrial process combustion is also projected to increase its share of NO_x emissions in the year 2000. However, coal-fired sources, especially large boilers, still dominate the projected ranking. The overall share of NO_x emissions contributed by these sources is larger in the year 2000 compared to 1977.

Finally, results of estimates of the ambient NO_x impact of various stationary sources also suggest that control of large coal-fired sources will be emphasized in the future. Appendix D presents the methodology used to estimate the ambient impact of stationary combustion sources, incorporating population exposure and pollutant dispersion. This methodology attempts to estimate nationwide ambient impact and differs in this and other ways from the more localized approaches used in Section 5. Appendix D also presents results of source flue gas multipollutant and NO_x potential impact. Table 6-3 summarizes the potential NO_x impact ranking from Appendix D by listing the 15 potentially most hazardous sources in 1977, based on NO_x emissions only. Here again, large coal-fired sources dominate. Coal-fired utility boilers occupy the top six places in the table. Oil- and gas-fired utility boilers account for five more places in the table. Large spark ignition IC engines also rank high in this table, as they did in both Tables 6-1 and 6-2.

Table 6-4 projects NO_x ambient impact to the year 2000, again based on the conservation scenario described in Appendix C. Rankings in this table remain remarkably similar to those in Table 6-3; the dominance

Table 6-2. NO_x[a] Emission Ranking of Stationary Combustion Equipment for the Year 2000 Conservation Scenario

Rank	Sector	Equipment Types	Fuel	Annual NO_x (Gg)	Cumulative (Gg)	Cumulative (percent)	1977 Rank	1985 Rank
1	Utility boilers	Tangential	Coal	4057.1	4057.1	32.5	1	1
2	Utility boilers	Opposed wall, (dry)	Coal	2310.5	6367.6	51.1	7	2
3	Utility boilers	Wall firing (dry)	Coal	673.5	7041.1	56.5	4	4
4	Utility boilers	Cyclone	Coal	501.0	7542.1	60.5	2	3
5	Utility boilers	Wall firing (wet)	Coal	387.8	7929.9	63.6	5	5
6	Industrial boilers	Stoker watertube <29 MW[b]	Coal	287.8	8217.7	65.9	>15	14
7	Reciprocating IC engines	75 kW to 75 kW/cyl[c]	Gas	267.2	8484.9	68.0	3	6
8	Reciprocating IC engines	>75 kW/cyl[c]	Gas	262.1	8744.0	70.1	6	7
9	Reciprocating IC engines	75 kW to 75 kW/cyl[c]	Oil[d]	245.4	8992.4	72.1	10	8
10	Industrial Process	Glass melting furnaces	Processed material	174.2	9166.6	73.5	>15	13
11	Utility boilers	Wall firing (dry)	Oil	143.4	9310.0	4.7	8	9
12	Industrial boilers	Tangential >73 MW[b]	Coal	127.3	9437.3	75.7	>15	>15
13	Industrial Process	Cement kilns	Processed material	123.9	9561.2	76.7	>15	>15
14	Industrial boilers	Single burner W-T <29 MW[b]	Gas	116.3	9677.5	77.6	>15	>15
15	Utility boilers	Tangential	Oil	114.1	9791.6	78.5	12	11

[a] NO_2 basis
[b] Heat input
[c] Power output
[d] Includes distillate and gasoline

Table 6-3. NO_x Potential Impact Ranking of Stationary Sources -- 1977

Rank	Sector	Equipment Type	Fuel	Normalized NO_x Impact Factor[c]
1	Utility boiler	Cyclone	Coal	1.00
2	Utility boiler	Tangential	Coal	0.77
3	Utility boiler	Wall firing (wet)	Coal	0.50
4	Utility boiler	Opposed Wall (dry)	Coal	0.36
5	Utility boiler	Wall firing (dry)	Coal	0.27
6	Utility boiler	Opposed wall (wet)	Coal	0.18
7	Utility boiler	Opposed wall	Gas	0.14
8	Utility boiler	Tangential	Oil	0.094
9	Industrial boiler	Opposed wall, >73 MW[a]	Gas	0.076
10	Utility boiler	Wall firing	Gas	0.067
11	Utility boiler	Opposed Wall	Oil	0.053
12	IC engine	Spark ignition, >75 kW/cyl[b]	Gas	0.048
13	Utility boiler	Wall firing	Oil	0.047
14	Industrial boiler	Cyclone, >73 MW[a]	Coal	0.032
15	Industrial boiler	Wall firing, >73 MW[a]	Gas	0.029

[a] Heat input

[b] Heat output

[c] Defined in Appendix D

Table 6-4. NO_x Potential Impact Ranking of Stationary Sources -- Year 2000, Conservation Scenario

Rank	Sector	Equipment Type[a]	Fuel	Normalized NO_x Impact Factor[b]	1977 Rank
1	Utility boiler	Tangential	Coal	1.00	2
2	Utility boiler	Cyclone	Coal	0.34	1
3	Utility boiler	Wall firing (wet)	Coal	0.16	3
4	Utility boiler	Wall firing (dry)	Coal	0.15	5
5	Utility boiler	Opposed wall (dry)	Coal	0.12	4
6	Utility boiler	Opposed wall (wet)	Coal	0.059	6
7	Utility boiler	Tangential	Oil	0.039	8
8	Industrial boiler	Tangential, >73 MW	Coal	0.035	>15
9	Utility boiler	Opposed wall	Oil	0.025	11
10	Industrial boiler	Stoker Watertube, <29 MW	Coal	0.025	>15
11	Industrial boiler	Opposed wall, >73 MW	Gas	0.023	9
12	Industrial boiler	Tangential, >73 MW	Oil	0.023	>15
13	Industrial boiler	Wall firing, >73 MW	Gas	0.016	15
14	Utility boiler	Wall firing	Oil	0.016	13
15	Gas turbine	Simple cycle, >15 MW	Oil	0.015	>15

[a] Equipment capacity ranges are heat input

[b] Defined in Appendix D

of large coal-fired sources continues, and smaller coal fired sources (industrial stokers) now appear.

Based on the above consideration, Table 6-5 lists the priority sources, the control of which should see emphasis in the future if air quality goals are to be attained and maintained. As noted in the table, stringent controls will be needed at least for

- Coal- and oil-fired utility and large industrial boilers
- Coal-fired industrial stokers
- Spark and compression ignition IC engines
- Large oil-fired gas turbines
- Several industrial process combustion sources

It must be emphasized, though, that, these only appear to be the most significant NO_x sources now and in the future; control of other equipment types will likely be required also.

6.2 COMBUSTION MODIFICATION CONTROL PRIORITIES

The preceding subsection identified those stationary combustion source types that, if controlled sufficiently will contribute most to allowing attainment and maintenance of projected air quality goals. Section 4 surveyed the NO_x controls currently developed or projected to be available before the year 2000, and evaluated and ranked these according to their cost-effectiveness and operational impacts. By applying these, in order, to the priority NO_x sources, needs for additional or more advanced control can be noted.

Table 6-6 provides such a matching. Shown in the table are the source types from Section 6-1 for which controls other than flue gas treatment techniques are developed or projected to be available. Attainable control levels with candidate control approaches are shown.

As noted from the table, control approaches for dry bottom coal- and oil-fired utility boilers and large industrial boilers (heat input greater than 73 MW) are either available or under development. Projected emission levels of 60 ng/J probably represent the realistically attainable combustion modification limit for pulverized coal combustion. Thus the research programs underway for wall-fired coal burning units and coal-fired tangential units should be vigorously pursued and research goals met.

Table 6-5. Priority Sources for NO_x Control

Sector	Equipment Type	Fuel	New Retrofit Control	Rankings			
				1977 NO_x Emissions	2000 NO_x Emissions	1977 NO_x Impact	2000 NO_x Impact
Utility boiler	Tangential	Coal	N,R	1	1	2	1
Utility boiler	Opposed wall (dry)	Coal	N,R	7	2	4	5
Utility boiler	Wall firing (dry)	Coal	N,R	4	3	5	4
Utility boiler	Cylone	Coal	R	2	4	1	2
Utility boiler	Wall firing (wet)	Coal	R	5	5	3	3
Industrial boiler	Stoker watertube, <29 MW[a]	Coal	N,R	>15	6	>15	10
IC engine	Spark ignition, >75 kW[b]	Gas	N,R	3,6	7,8	12	>15
Utility boiler	Opposed wall (wet)	Coal	R	11	>15	6	6
Utility boiler	Wall firing	Oil	R	8	11	13	14
Utility boiler	Tangential	Oil	R	12	15	8	7
Industrial boiler	Tangential, >73 MW[a]	Coal	N,R	>15	12	>15	8
Utility boiler	Opposed wall	Oil	R	>15	>15	11	9
IC engine	Compression ignition 75 kW - 75 kW/cyl[b]	Oil	N,R	10	9	>15	>15
Gas turbine	Simple cycle, >15 MW	Oil	N,R	>15	>15	>15	15
Industrial processes	Glass melting cement kilns, refinery heaters	Various	N,R	>15	10,13	>15	>15

[a] Heat input
[b] Power output

Table 6-6. Source Control Priorities

Sector	Equipment Type	Fuel	New/Retrofit Application	Control Level (ng/J)	Control Strategy Control Approach[a]	Date Available
Utility Boiler Industrial Boiler	Tangential Tangential, >73 MW	Coal		280	Baseline	
			N,R	215	OFA	Now
			N,R	129	OFA + TDN	1983
	Opposed Wall and Wall Firing (dry)	Coal		430	Baseline	
			N,R	258	OFA	Now
			N,R	215	LNB	Now
			N,R	172	LNB + OFA	Now
			N,R	129	LNB + OFA + TDN	1983
			N,R	86	Advanced LNB	1985
			N	60	Advanced Burner/ Furnace Concepts	1985
	Cyclone	Coal		680	Baseline	
				610	LEA	
	Opposed Wall and Wall Firing (wet)	Coal		790	Baseline	
			R	550	BOOS	Now
	Tangential	Oil		215	Baseline	
			R	129	BOOS, OFA	Now
			R	86	BOOS, OFA + FGR	Now
			R	43	Above CM + TDN	1981
Utility Boiler	Opposed Wall and Wall Firing	Oil		215	Baseline	
			R	129	BOOS, OFA or LNB	Now
			R	86	(BOOS, OFA, or LNB) + FGR	Now
			R	43	Above CM + TDN	1981
Industrial	Stoker Watertube - Spreader	Coal		265	Baseline	
			N,R	215	LEA + OFA	1983
			N,R	172	TDN	1993
			N,R	129	LEA + OFA + TDN	1983
	- Chain Grate and Underfeed			150	Baseline	
			N,R	129	LEA	Now
IC Engine	Spark Ignition >75 KW	Gas		1500	Baseline	
			N,R	1700	EGR	Now
			N,R	1100	Retard	Now
			N,R	900	A/F Increase	Now
	Compression Ignition >75 KW	Oil		1700	Baseline	
			N,R	1400	EGR	Now
			N,R	1200	Retard	Now
			N,R	1000	A/F Increase + Retard	Now
		Dual Fuel		1100	Baseline	
			N,R	900	EGR	Now
			N,R	800	Retard	Now
			N,R	700	A/F Increase	Now
Gas Turbine	Simple Cycle,>15 MW	Oil		310	Baseline	
			N,R	130	Water Injection	Now
			N	130	Dry Control	1983
			N	10	Catalytic Combustion	1990
Industrial Processes	Glass Melting Furnaces Cement Kilns Refinery Heaters	Various		Varies (15 Percent Reduction Typical)	Baseline	
					LEA	Now

[a] Abbreviations are defined in Appendix E.

The situation for wet bottom and cyclone units is less desirable. Control development for these source categories has been deferred in the past because these units do not respond well to the standard combustion modification techniques. Further, because they are such high NO_x emitters, they are no longer being sold, thus impetus for control development to incorporate into new units has been removed. However, both emissions and ambient impact projections show these sources to remain quite significant into the 21st century. Control development programs for these sources should be given consideration.

For the industrial boiler sector, Section 6.1 concluded that stoker watertube units will be priority NO_x sources in the future. However, Table 6-6 shows that projected attainable control levels, at least for spreader stoker units, remain relatively high and even these require the use of ammonia injection. Thus, control development for these units should be encouraged, and the current IERL-RTP program to develop these controls should be continued.

Similar conclusions apply for IC engines since this sector has the highest NO_x emission factor of all stationary combustion sources. Currently projected combustion modification control techniques are only capable of reducing emissions from these units about 40 percent, however. Thus further control development for these sources, as currently initiated, should be encouraged.

For gas turbines, currently envisioned control capabilities seem sufficient. However, this conclusion requires the successful development and implementation of dry controls and catalytic combustion for turbine applications. This should be pursued through the continuation of ongoing programs.

Finally, the industrial process combustion sector represents the source category for which the least control technology has been developed. Currently, low excess air firing, giving about 20 percent NO_x reductions, is essentially the only control approach. Since elements of this source category are projected to become important future NO_x sources, control development programs as recently initiated, should be pursued.

In summary, the priority combustion modification needs for the future beyond those being actively researched in programs now underway are:

- Further control of tangential coal-fired utility and large industrial boilers to the 60 ng/J level through the continuation and success of ongoing programs
- Further control of opposed wall and wall coal-fired utility and large industrial boilers to the 60 ng/J level through the continuation and success of ongoing programs
- Effective retrofit control of cyclone and wet bottom wall coal-fired utility and large industrial boilers
- Further control of stoker-fired industrial boilers, particularly spreader stokers, through the continuation of ongoing programs
- Further control of large IC engines, both spark and compression ignition, through the continuation of ongoing programs
- Control techniques for industrial process combustion; particularly glass melting furnaces, cement kilns, and refinery process heaters, through the continuation of ongoing programs

6.3 POLLUTANT PRIORITIES

The discussion in the preceding subsections focused on NO_x sources and NO_x control priorities. However, one goal of the NO_x EA was to evaluate the overall environmental impact of stationary source combustion, identify other combustion generated pollutants of concern, and assess the effect of combustion modification control on emissions of these pollutants. Section 3 presented the results of a source analysis model (SAM 1A) evaluation of test program results. From this evaluation, the potentially hazardous combustion generated flue gas pollutants identified in addition to NO_x are

- Sulfur oxides: SO_2 and vapor phase SO_3 from coal- and oil-fired sources, and condensed sulfate ($SO_4^=$) from coal-fired sources
- CO and CO_2
- Organic acids: potentially maleic acid
- Trace elements: As, Fe, Be, and possibly Ca, Ba, B, Ti, Ca, Cd, Pb, and V. Coal-fired sources are generally more hazardous due to these.

The oxides of sulfur were by far the most potentially hazardous species; in most cases the potential hazard presented by SO_2 exceeded that presented by NO_x.

More detailed (Level 2) elucidation of the organic content of the flue gas is needed in future efforts; carboxylic acid emission levels are potentially hazardous only if all organic matter determined exists as maleic acid (the most toxic carboxylic acid on the MEG list). Thus, in addition to specifically analyzing for polycyclic organic (POM) species, and organic priority pollutants, future testing should define the organic acid composition of the flue gas organics.

The application of combustion modification controls, in general, does not affect the potential hazard presented by any of the above pollutants. CO emissions are unchanged, or increase only slightly, SO_2 emissions vary only with fuel sulfur content, and SO_3 and condensed $SO_4^=$ emissions are unchanged or decrease slightly. POM emissions sometimes increase with NO_x control application, but never to potentially hazardous levels.

Potentially hazardous ash stream pollutants from coal-fired sources are the trace elements Fe, Mn, Cr, Ni, Be, Ba, Pb, and occasionally As, Se, Tl, and Sn. However, the potential hazard presented by the ash streams is lower, by several orders of magnitude, from that presented by the flue gas stream. Combustion modification control application has essentially no effect on emission rates of these species.

Based on the above, it can be concluded that the NO_x control methods investigated in the NO_x EA test program (burners out of service applied to coal- and oil-fired utility boilers, flue gas recirculation applied to an oil-fired utility boiler, high overfire air and low excess air applied to industrial stokers, water injection applied to an oil-fired gas turbine, and the combustion gas recirculation (Blueray System) oil-fired residential warm air furnace) are environmentally sound. The potential adverse impact of the controlled source is either demonstrably decreased, or is unchanged with effects of NO_x control applications of lesser magnitude than those attributable to day to day fuel composition changes or operational changes.

Of course, in the absence of test data, this conclusion cannot be extended to the combustion modification methods not tested. In addition, this conclusion only holds for the sources/fuels controls tested under steady operation. Effects of transient and upset conditions still await evaluation.

APPENDIX A

NO_x EA PROGRAM DOCUMENTATION

Environmental Assessment Reports

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General Support

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APPENDIX B

BASELINE MULTIMEDIA EMISSIONS INVENTORY (1977)

This appendix presents a baseline emissions inventory for stationary sources. Section B.1 describes how sources were characterized. Sections B.2 and B.3 discuss how emission factors and equipment fuel consumption were determined. Section B-4 presents the summary of NO_x emissions from stationary combustion sources.

B.1 CHARACTERIZATION OF NO_x SOURCES

Stationary sources were characterized by:

- Grouping source types according to NO_x formation mechanism and nature of release into the atmosphere
- Categorizing specific stationary combustion sources according to equipment and/or fuel characteristics affecting pollutant generation
- Giving consideration to current and projected use and design trends

Figure B-1 categorizes the major sources of NO_x emissions. The major emphasis throughout this report is on the fuel combustion sources of NO_x bracketed at the top right of the figure. A detailed characterization of the combustion sources is given in Table B-1 which shows the equipment/fuel categories that merit separate consideration in the subsequent NO_x emissions inventory. This list results from applying the characterization criteria mentioned above to all nationwide NO_x sources presented in Figure B-1.

B.2 DEVELOPMENT OF EMISSIONS FACTORS

Emission factors were compiled for the following fuels: lignite, bituminous and anthracite coal, distillate and residual oil, natural gas and process gas. Whenever possible, emission factors are expressed in terms of fuel inputs, i.e., nanograms NO_2 per Joule heat input.

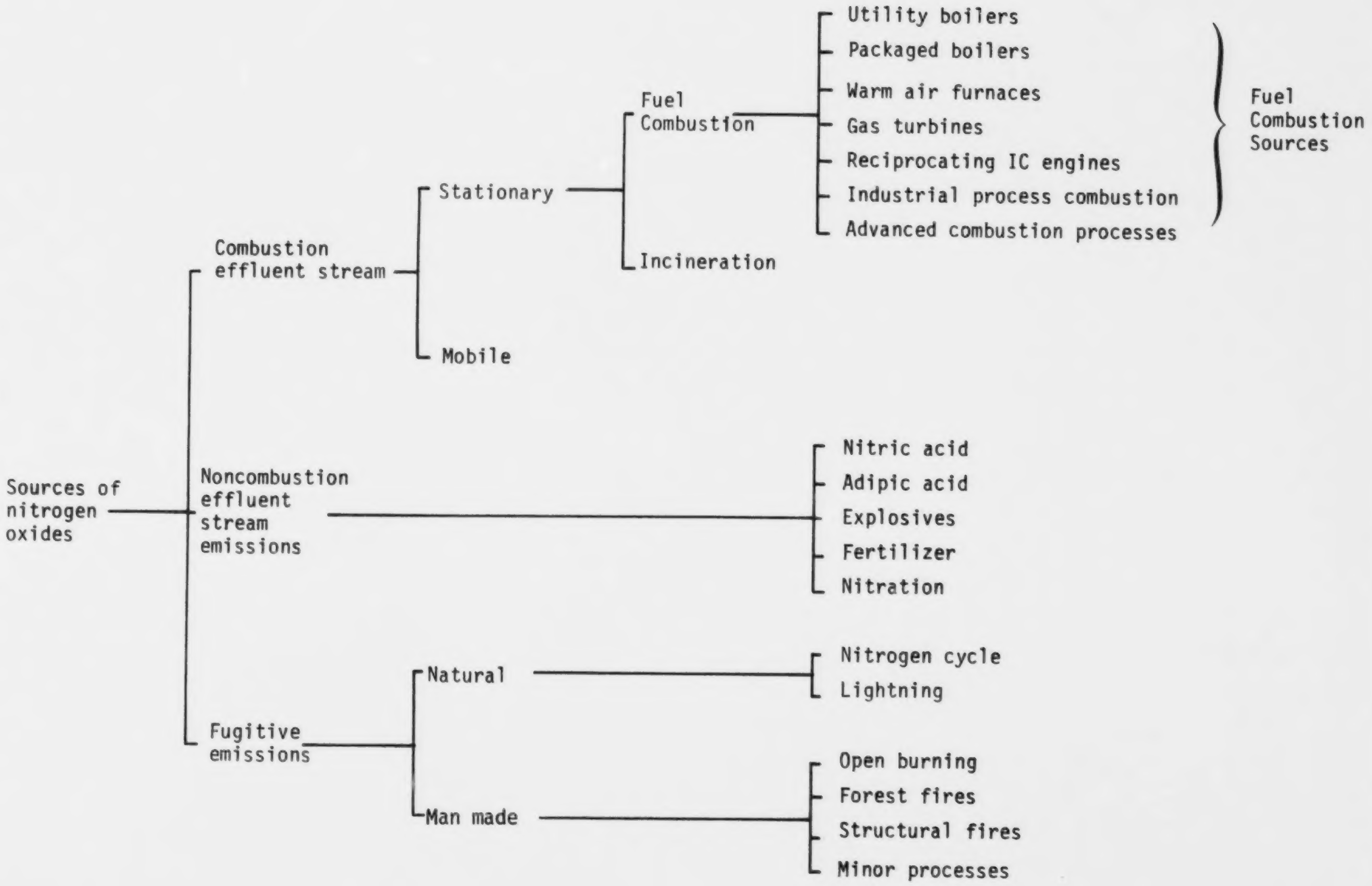

Sources of nitrogen oxides
Combustion effluent stream
Stationary
Fuel Combustion
Utility boilers
Packaged boilers
Warm air furnaces
Gas turbines
Reciprocating IC engines
Industrial process combustion
Advanced combustion processes
Fuel Combustion Sources
Incineration
Mobile
Noncombustion effluent stream emissions
Nitric acid
Adipic acid
Explosives
Fertilizer
Nitration
Fugitive emissions
Natural
Nitrogen cycle
Lightning
Man made
Open burning
Forest fires
Structural fires
Minor processes

Figure B-1. Sources of Nitrogen Oxide Emissions

Table B-1. Significant Stationary Fuel Combustion Equipment Types/Major Fuels

	Fuel
Utility Sector (Field Erected Watertubes)	
Tangential	PC, O, G
Wall-fired -- dry bottom	PC, O, G
Wall-fired -- wet bottom	PC
Horizontally opposed and turbo furnace -- dry bottom	PC, O, G
Horizontally opposed and turbo furnace -- wet bottom	PC
Cyclone	C, O
Vertical and stoker	C
Packaged Boiler Sector	
Tangential >73 MW[a] (250 MBtu/hr)	PC, O, G
Wall-fired -- dry bottom >73 MW[a] (250 MBtu/hr)	PC, O, G
Wall-fired -- wet bottom >73 MW[a] (250 MBtu/hr)	PC
Horizontally opposed -- dry bottom >73 MW[a] (250 MBtu/hr)	PC, O, G
Horizontally opposed -- wet bottom >73 MW[a] (250 MBtu/hr)	PC
Cyclone >73 MW[a] (250 MBtu/hr)	C, O, G
Vertical and stoker >73 MW_a (250 MBtu/hr)	C
Wall-fired watertube 29 to 73 MW[a] (100 to 250 MBtu/hr)	C, O, G, PG
Stoker watertube 29 to 73 MW_a (100 to 250 MBtu/hr)	C
Watertube <29 MW[a] (100 MBtu/hr)	C, O, G, PG
Stoker watertube <29 MW[a] (<100 MBtu/hr)	C
Scotch firetube <29MW[a] (<100 MBtu/hr)	O, G, PG
Stoker firetube <29 MW[a] (<100 MBtu/hr)	C
HRT firetube <29 MW[a] (<100 MBtu/hr)	O, G
Firebox firetube <29 MW[a] (<100 MBtu/hr)	O, G, PG
Cast iron	C, O, G
Residential/commercial	C, O, G
Warm Air Furnace Sector	
Central heaters	O,G
Space Heaters	O,G
Other residential Combustion	O,G
PC -- Pulverized coal C -- Stoker coal or other coal O -- Oil G -- gas PG -- Process gas	

[a] Heat input

[b] Power output

Table B-1. Concluded

	Fuel
Gas Turbines	
Large >15 MW[b] (>20,000 hp)	O, G
Medium 4 to 15 MW[b] (5,000 to 20,000 hp)	O, G
Small >4MW[b] (>5,000 hp)	O, G
Reciprocating IC Engines	
Large bore >75 kW/cyl[b] (>100 hp/cyl)	O, G
Medium 75 kW to 75 kW/cyl[b] (100 hp to 100 hp/cyl)	O, G
Small <75 kW[b] (<100 hp)	O, G
Industrial Process Heating	
Glass melting furnaces	O, G
Glass annealing lehrs	O, G
Cement kilns	C, O, G
Petroleum refinery	
Process heaters	O, G, PG
Catalytic crackers	O, G, PG
Brick amd ceramic kilns	O, G
Iron and steel	
Coke oven underfire	G, PG
Sintering machines	O, G, PG
Soaking pits and reheat ovens	C, O, G, PG
PC -- Pulverized coal C -- Stoker coal or other coal O -- Oil G -- gas PG -- Process gas	

[a] Heat input
[b] Power output

However, for the industrial process heating sector emission factors are expressed as a function of product output.

The emission factors were obtained from AP-42 (Reference B-1) and its supplements, from a survey of existing literature, and from results of ongoing test programs and the NO_x EA test program. Whenever possible, AP-42 and its supplements were used as sources. Whenever emission factors were not available, they were estimated from test results on similar equipment. Specific sources of emission factors for the combustion equipment classifications are as follows:

- Utility Boilers: AP-42 supplements (References B-2 through B-4) and updates (Reference B-5)
- Industrial Boilers: Summary of Industrial Boiler Population (Reference B-6) as well as AP-42 and its supplements (References B-1 through B-4)
- Warm Air Furnaces: Recent field studies (References B-7, B-8) and an AP-42 supplement (Reference B-2)
- Gas Turbines: Gas Turbine Standards Support and Environmental Impact Statement (Reference B-9) and an AP-42 supplement (Reference B-10)
- Reciprocating IC Engines: IC Engine Standard Support and Environmental Impact Statement (Reference B-11)
- Industrial Process Combustion: Various sources including References B-12 through B-14

B.3 COMPILATION OF FUEL CONSUMPTION

The final input required to develop an emissions inventory is the fuel consumption for each equipment type. Fuel use data for 1977 were used to update the previously compiled 1974 inventory (Reference B-15). These new data are based on the most recent information and show a lower fuel consumption estimate than was previously used for industrial boilers, warm air furnaces and gas turbines. The sources used to determine the amount of fuel used by the major stationary source equipment sectors are described below:

- Utility Boilers: trade group statistics (Reference B-16), government data (Reference B-17), and survey reports (Reference B-18). Coal, oil, and gas accounted for 64, 19 and 26 percent of fuel consumption respectively

- Industrial/Commercial Boilers: survey studies (References B-6, B-19, B-20) and government data (References B-17, B-21, B-22). In 1977 energy supplied to these boilers amounted to roughly one quarter of the total fossil fuels consumed in stationary combustion sources. Coal, oil and gas accounted for 8, 31 and 61 percent of the fuel consumption respectively. Coal is used almost exclusively for the large watertubes.
- Warm Air Furnaces: 1976 U.S. Census data (Reference B-23) and U.S. Department of Energy data (References B-17, B-21). Oil and gas accounted for 42 and 58 percent respectively of the fuel used in 1977.
- Gas Turbines; Gas Turbine Standard Support and Environmental Impact Statement (Reference B-9) and U.S. Department of Energy data (Reference B-17)
- Reciprocating IC Engines: IC Engine Background Information Document (Reference B-11). Natural gas is the major fuel, particularly in the larger units
- Industrial Process Heating: Primarily industrial survey studies, trade groups and government data (References B-12, B-17, B-21, and B-24 through B-36)

Table B-2 shows the fuel consumption inventory assembled for stationary combustion sources, for the fuels inventoried, along with the total NO_x emissions for these sources for 1977. In calculating NO_x emission the extent of NO_x control applied to each source/fuel combination was considered. This is reflected in the column labeled "Control Factors." Thus, total NO_x emissions from a source are calculated as the product of fuel use (obtained as described above) with uncontrolled emission factor (obtained as discussed in Section B-2), multiplied by the term (1-Control Factor) to correct for the extent the source category was controlled for NO_x nationwide in 1977.

B.4 SUMMARY OF NO_x EMISSIONS

Stationary source NO_x emissions are subdivided by major equipment sector in Table B-3. The NO_x emission estimates for utility boilers consider the use of NO_x controls, although existing NO_x controls cause only a small reduction in the nationwide total. In 1977 control of utility boilers resulted in a 3.1 percent decrease.

Table B-2. Stationary Fuel Consumption and NO_x Emissions - 1977

EQUIPMENT TYPE	FIRING TYPE	FUEL TYPE	FUEL USAGE (PJ)	UNC. EMIS. FACTORS (NG NO2/J)	CONTROL FACTORS	TOTAL NOX EMISSIONS (GG NO2)
UTILITY BOILERS	TANGENTIAL BOILERS	EASTERN BITUMIN.	2860.0	250.0		715.0
		CENTRAL BITUMIN.	1828.0	250.0		457.0
		WESTERN BITUMIN.	948.0	250.0		237.0
		LIGNITE	70.0	190.0		13.3
		HIGH S RES. OIL	198.0	120.0		23.8
		MED S RES. OIL	496.0	120.0		59.5
		LOW S RES. OIL	641.0	120.0		76.9
		DISTILLATE OIL	36.0	120.0		4.3
		NATURAL GAS	716.0	80.0	.014	56.5
	WALL FIRED BOILER	EASTERN BITUMIN.	1059.0	360.0	.007	379.6
		CENTRAL BITUMIN.	644.0	360.0	.007	230.2
		WESTERN BITUMIN.	351.0	360.0	.007	125.5
		LIGNITE	6.0	350.0		2.1
		HIGH S RES. OIL	198.0	190.0	.090	34.2
		MED S RES. OIL	497.0	190.0	.090	85.9
		LOW S RES. OIL	641.0	190.0	.090	110.8
		DISTILLATE OIL	170.0	190.0		32.3
		NATURAL GAS	1550.0	140.0	.036	209.1
	OPPOSED WALL BOILER	EASTERN BITUMIN.	460.0	480.0	.195	177.7
		CENTRAL BITUMIN.	348.0	480.0	.195	134.5
		WESTERN BITUMIN.	152.0	480.0	.195	58.7
		LIGNITE	12.0	380.0		4.6
		HIGH S RES. OIL	80.0	200.0	.257	11.9
		MED S RES. OIL	200.0	200.0	.257	29.7
		LOW S RES. OIL	259.0	200.0	.257	38.5
		DISTILLATE OIL	15.0	200.0		3.0
		NATURAL GAS	797.0	230.0	.114	162.4
	CYCLONE BOILER	EASTERN BITUMIN.	149.0	650.0		96.8
		CENTRAL BITUMIN.	1210.0	650.0		786.5
		LIGNITE	129.0	320.0		41.3
		HIGH S RES. OIL	11.0	250.0		2.7
		MED S RES. OIL	26.0	250.0		6.5
		LOW S RES. OIL	35.0	250.0		8.8
		NATURAL GAS	57.0	250.0		14.2
	VERTICAL + STOKER BOILER	ANTHRACITE	102.0	310.0		31.6
		EASTERN BITUMIN.	103.0	320.0		33.0
		CENTRAL BITUMIN.	103.0	320.0		33.0
		LIGNITE	8.0	320.0		2.6
	FRONT WALL FIRING, WET	EASTERN BITUMIN.	435.0	850.0		369.7
		CENTRAL BITUMIN.	263.0	850.0		223.5
		WESTERN BITUMIN.	144.0	850.0		122.4
		LIGNITE	6.0	380.0		2.3
	HORIZONTALLY OPPOSED,WET	EASTERN BITUMIN.	123.0	850.0		104.5
		CENTRAL BITUMIN.	74.0	850.0		62.9
		WESTERN BITUMIN.	41.0	850.0		34.8
		LIGNITE	11.0	380.0		4.2

Table B-2. (Continued)

EQUIPMENT TYPE	FIRING TYPE	FUEL TYPE	FUEL USAGE (PJ)	UNC. EMIS. FACTORS (NG NO2/J)	CONTROL FACTORS	TOTAL NOX EMISSIONS (GG NO2)
INDUSTRIAL BOILERS	PKG WALLFIRED WT 29-73MW	DISTILLATE OIL	93.0	200.0		18.6
		NATURAL GAS	609.0	120.0		73.1
		PROCESS GAS	85.0	120.0		10.2
		BIT/LIG COAL	116.0	300.0		34.8
		RESIDUAL OIL	362.0	200.0		72.4
	PKG STOKER W-T 29-73MW	BIT/LIG COAL	106.0	230.0		24.4
	SINGLE BURNER W-T <29MW	DISTILLATE OIL	112.0	55.0		6.2
		NATURAL GAS	1109.0	60.0		65.5
		PROCESS GAS	85.0	60.0		5.1
		BIT/LIG COAL	72.0	320.0		23.0
		RESIDUAL OIL	339.0	160.0		54.2
	SCOTCH FIRETUBE <29MW	DISTILLATE OIL	148.0	60.0		8.9
		NATURAL GAS	540.0	40.0		21.6
		PROCESS GAS	11.0	40.0		.4
		RESIDUAL OIL	174.0	150.0		26.1
	FIREBOX FIRETUBE <29MW	DISTILLATE OIL	134.0	60.0		8.0
		NATURAL GAS	499.0	40.0		20.0
		PROCESS GAS	11.0	40.0		.4
		RESIDUAL OIL	112.0	150.0		16.8
	STOKER WATER TUBE <29MW	ANTHRACITE	5.0	270.0		1.3
		BIT/LIG COAL	349.0	230.0		80.3
	CAST IRON BOILERS	DISTILLATE OIL	348.0	68.0		23.7
		NATURAL GAS	1764.0	52.0		91.7
		BIT/LIG COAL	97.0	150.0		14.5
		RESIDUAL OIL	470.0	180.0		84.6
	STOKER FIRETUBE <29MW	ANTHRACITE	8.0	270.0		2.2
		BIT/LIG COAL	102.0	230.0		23.5
	HRT BOILER <29MW	DISTILLATE OIL	88.0	60.0		5.3
		NATURAL GAS	297.0	40.0		11.9
		RESIDUAL OIL	68.0	150.0		10.2
	RES/COMM STEAM + HOT WAT	ANTHRACITE	24.1	180.0		4.3
		DISTILLATE OIL	1391.0	56.0		77.9
		NATURAL GAS	2070.0	40.0		82.8
		BIT/LIG COAL	18.9	150.0		2.8
		RESIDUAL OIL	109.5	160.0		17.5
	TANGENTIAL BOILERS >73MW	EASTERN BITUMIN.	74.0	260.0		19.2
		CENTRAL BITUMIN.	45.0	260.0		11.7
		WESTERN BITUMIN.	25.0	260.0		6.5
		LIGNITE	1.0	220.0		.2
		HIGH S RES. OIL	20.0	170.0		3.4
		MED S RES. OIL	51.0	170.0		8.7
		LOW S RES. OIL	65.0	170.0		11.0
		DISTILLATE OIL	44.0	170.0		7.5
		NATURAL GAS	398.0	110.0		43.8
	WALL FIRED - DRY >73MW	EASTERN BITUMIN.	30.0	300.0		9.0
		CENTRAL BITUMIN.	17.0	300.0		5.1
		WESTERN BITUMIN.	10.0	300.0		3.0
		LIGNITE	.5	380.0		.2
		HIGH S RES. OIL	20.0	200.0		4.0
		MED S RES. OIL	51.0	200.0		10.2
		LOW S RES. OIL	65.0	200.0		13.0
		DISTILLATE OIL	207.0	200.0		41.4

Table B-2. (Continued)

EQUIPMENT TYPE	FIRING TYPE	FUEL TYPE	FUEL USAGE (PJ)	UNC. EMIS. FACTORS (NG NO2/J)	CONTROL FACTORS	TOTAL NOX EMISSIONS (GG NO2)
INDUSTRIAL BOILERS	WALL FIRED - DRY >73MW	NATURAL GAS	862.0	120.0		103.4
	OPPOSED WALL - DRY >73MW	EASTERN BITUMIN.	9.0	480.0		4.3
		CENTRAL BITUMIN.	6.0	480.0		2.9
		WESTERN BITUMIN.	3.0	480.0		1.4
		LIGNITE	.4	380.0		.2
		HIGH S RES. OIL	8.0	200.0		1.6
		MED S RES. OIL	20.0	200.0		4.0
		LOW S RES. OIL	27.0	200.0		5.4
		DISTILLATE OIL	20.0	200.0		4.0
		NATURAL GAS	443.0	230.0		101.9
	CYCLONE BOILERS >73MW	EASTERN BITUMIN.	5.0	650.0		3.2
		CENTRAL BITUMIN.	37.0	650.0		24.0
		LIGNITE	3.0	320.0		1.0
		HIGH S RES. OIL	1.0	250.0		.3
		MED S RES. OIL	3.0	250.0		.7
		LOW S RES. OIL	4.0	250.0		1.0
		NATURAL GAS	21.0	250.0		5.2
	VERTICAL/STOKER >73MW	ANTHRACITE	3.0	310.0		.9
		EASTERN BITUMIN.	3.0	320.0		1.0
		CENTRAL BITUMIN.	3.0	320.0		1.0
		LIGNITE	.2	320.0		.1
	WALL FIRED - WET >73MW	EASTERN BITUMIN.	13.0	850.0		11.0
		CENTRAL BITUMIN.	8.0	850.0		6.8
		WESTERN BITUMIN.	4.0	850.0		3.4
		LIGNITE	.5	380.0		.2
	OPPOSED WALL - WET >73MW	EASTERN BITUMIN.	4.0	850.0		3.4
		CENTRAL BITUMIN.	2.0	850.0		1.7
		WESTERN BITUMIN.	1.0	850.0		.9
		LIGNITE	.6	380.0		.2
WARM AIR FURNACES	WARM AIR CENTRAL FURNACE	NATURAL GAS	2300.0	35.0		80.5
		OIL	1660.0	25.0		41.5
	WARM AIR SPACE HEATER	NATURAL GAS	570.0	35.0		19.9
		OIL	420.0	25.0		10.5
	MISCELLANEOUS COMBUSTION	NATURAL GAS	1100.0	35.0		38.5
		OIL	790.0	25.0		19.7
GAS TURBINES	SIMPLE CYCLE >15 MJ/S	DISTILLATE OIL	160.0	360.0	.002	57.5
		NATURAL GAS	130.0	190.0	.003	24.6
	SIMPLE CYCLE 3.7-15 MJ/S	DISTILLATE OIL	370.0	210.0	.002	77.6
		NATURAL GAS	310.0	120.0	.003	37.1
	SIMPLE CYCLE <3.7 MJ/S	DISTILLATE OIL	48.0	180.0	.002	8.6
		NATURAL GAS	48.0	120.0	.003	5.7
RECIPROCATING I/C ENGINE	C. I. >75 KJ/S/CYL	DISTILLATE OIL	53.0	1430.0		75.8
		DUAL (OIL + GAS)	54.0	1350.0		72.9
	S. I. >75 KJ/S/CYL	NATURAL GAS	360.0	1750.0		630.0
	C. I. 75KJ/S-75 KJ/S/CYL	DISTILLATE OIL	140.0	1330.0		185.2
	S. I. 75KJ/S-75 KJ/S/CYL	NATURAL GAS	494.0	1600.0		790.4
		GASOLINE	31.0	740.0		22.9
	C.I. <75 KJ/S	DISTILLATE OIL	32.0	1300.0		41.6
	S. I. <75 KJ/S	NATURAL GAS	77.9	1600.0		124.6
		GASOLINE	156.0	250.0		39.0

Table B-2. (Concluded)

EQUIPMENT TYPE	FIRING TYPE	FUEL TYPE	ANNUAL PRODUCTION (Gg)	UNC. EMIS. FACTORS (g NO_2/kg PRODUCT)	CONTROL FACTORS	TOTAL NOX EMISSIONS (GG NO2)
IND. PROCESS COMBUSTION	CEMENT KILNS	PROCESSED MAT'L	68900.0	1.3		89.6
	GLASS MELTING FURNACES	PROCESSED MAT'L	22000.0	4.1		90.2
	GLASS ANNEALING LEHRS	PROCESSED MAT'L	21500.0			.4
	COKE OVEN UNDERFIRE	PROCESSED MAT'L	43600.0	.1		5.1
	STEEL SINTERING MACHINES	PROCESSED MAT'L	31800.0	.5		16.5
	OPEN HEARTH FURNCE (OIL)	PROCESSED MAT'L	18200.0	.6		11.3
	BRICK + CERAMIC KILNS	PROCESSED MAT'L	20800.0	.2		4.8
	CAT CRACKING (FCCU)	PROCESSED MAT'L	275030.0	.2		55.0
	REFINERY FLARES	PROCESSED MAT'L	8255.5	1.0		8.3
	IRON + STEEL FLARES	PROCESSED MAT'L	273.5	1.0		.3
	REF. HTR.-NAT. DRAFT,GAS	PROCESSED MAT'L	1654.0	50.0		82.7
	REF. HTR.-NAT. DRAFT,OIL	PROCESSED MAT'L	215.0	150.0		32.2
	REF. HTR.-FOR. DRAFT,GAS	PROCESSED MAT'L	204.0	110.0		22.4
	REF. HTR.-FOR. DRAFT,OIL	PROCESSED MAT'L	68.0	180.0		12.2

RESOURCE UNITS: TOTAL: 24.4526

SYSTEM: 24.4526
APPLICATION: 0.0000

Table B-3. Summary of 1977 Stationary NO_x[a], Emissions by Sector and Fuel Type

	NO^x Production Gg/yr (% of total)			Total by Sector	
Sector	Coal	Oil	Gas	(% of total)	Cumulative (%)
Utility Boilers	4483 (42.7)	529 (5.0)	442 (4.2)	5454 (52)	52.0
Industrial Boilers[b]	334 (3.2)	547 (5.2)	638 (6.1)	1519 (14.5)	66.5
Warm Air Furnaces	--	72 (0.7)	139 (1.3)	211 (2.0)	68.5
Gas Turbines	--	144 (1.4)	67 (0.6)	211 (2.0)	70.5
Reciprocating IC Engines	-- --	367[c] (3.5)	1618[d] (15.4)	1985 (18.9)	89.4
Industrial Process Heating	--	--	--	429 (4.1)	93.5
Noncombustion	--	--	--	203 (2.0)	95.5
Incineration	--	--	--	42 (0.4)	95.9
Fugitive	--	--	--	435 (4.1)	100
Total	4817	1659	2904	10,489	

[a] NO_2 basis
[b] Includes steam and hot water commerical and residential heating units
[c] Includes gasoline
[d] Includes dual fuels (oil and gas)

Table B-4 ranks equipment/fuel combinations by annual nationwide NO_x emissions. The 15 most significant sources account for 67 percent of total NO_x emissions from stationary sources. However, the ranking depends on both the total fuel used by the equipment/fuel type and the emission factor. Thus, a high ranking does not necessarily imply that the given source is itself a high emitter but only that the contribution from the entire category is significant. As shown utility boilers and large reciprocating IC engines are the largest NO_x contributors.

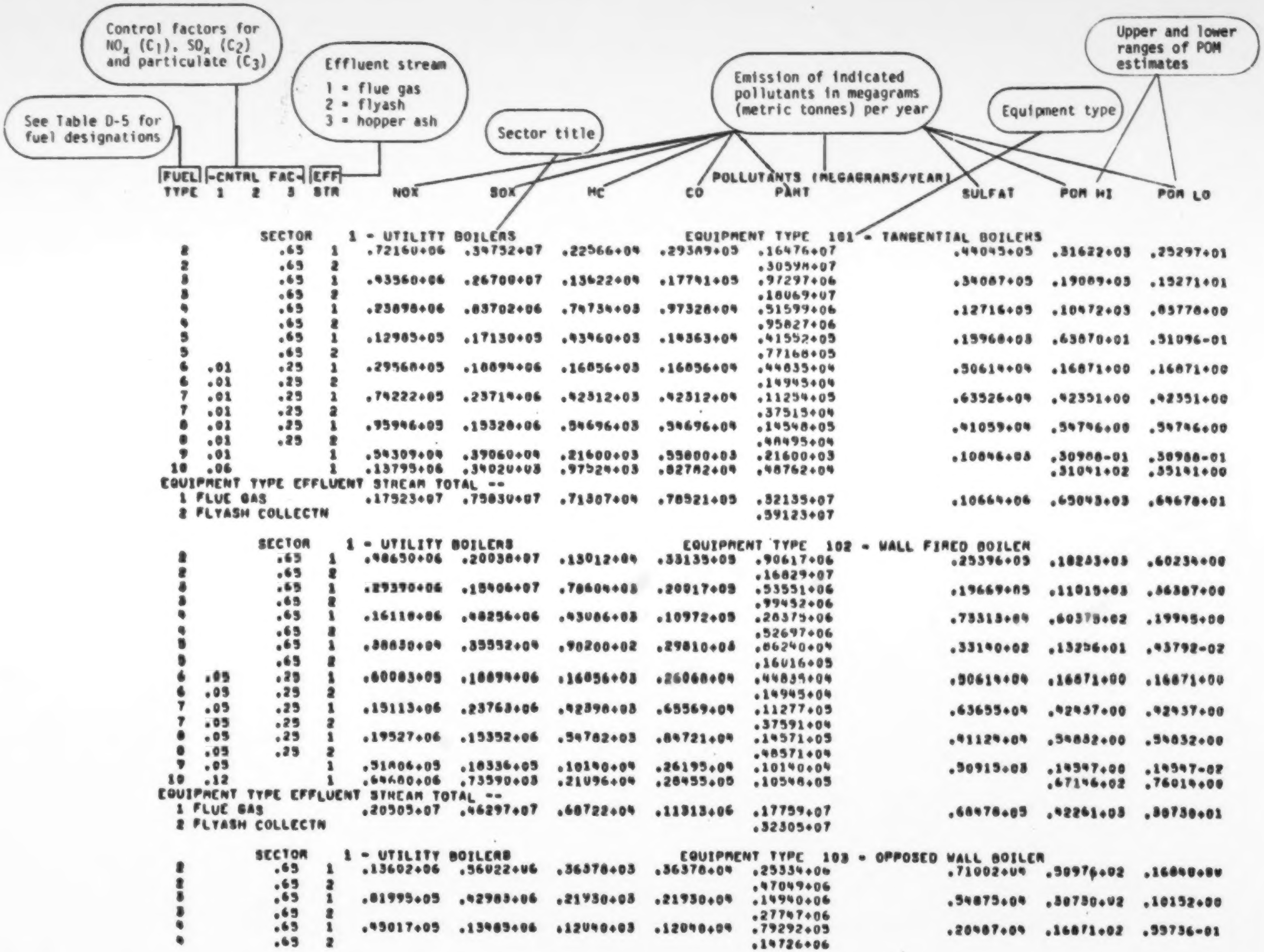
The complete multimedia emissions inventory assembled for all the source/fuel/pollutant combinations is shown in Tables B-6 through B-9. An annotated sample page of the output is shown in Figure B-2, and a list of fuel type codes is given in Table B-5. The table in which a particular pollutant is found is:

Table B-6 Pollutant Group i	NO_x, SO_x, HC, CO, Part., Sulfate, POM
Table B-7 Pollutant Group ii	Ba, Be, B, Cr, Co, Cu, Pb, Mn, Hg, Mo
Table B-8 Pollutant Group iii	Ni, V, Zn, Zr, As, Bi, Al, Sb, Cd, Se
Table B-9 Pollutant Group iv	P, Sr

Table B-4. NO_x[a] Mass Emission Ranking of Stationary Combustion Equipment for 1977

Rank	Sector	Equipment Types	Fuel	Annual NO_x (Gg)	Cumulative (Gg)	Cumulative[d] (percent)
1	Utility boilers	Tangential	Coal	1422.3	1422.3	13.5
2	Utility boilers	Cyclone furnace	Coal	924.6	2346.9	22.3
3	Reciprocating IC engines	75 kW to 75 kW/cyl[b]	Gas	790.4	3137.3	29.8
4	Utility boilers	Wall firing (dry)	Coal	736.4	3873.7	36.8
5	Utility boilers	Wall firing (wet)	Coal	717.9	4591.6	43.6
6	Reciprocating IC engines	>75 kW/cyl	Gas	702.9	5294.5	50.3
7	Utility boilers	Opposed wall (dry)	Coal	375.5	5670.0	53.9
8	Utility boilers	Wall firing	Oil	263.2	5933.2	56.4
9	Utility boilers	Wall firing	Gas	209.1	6142.3	58.4
10	Reciprocating IC engines	75 kW to 75 kW/cyl	Oil[c]	209.1	6351.4	60.4
11	Utility Boilers	Opposed wall (wet)	Coal	206.4	6557.8	62.4
12	Utility boilers	Tangential	Oil	164.5	6722.3	64.0
13	Utility Boilers	Opposed wall	Gas	162.4	6884.7	65.5
14	Reciprocating IC engines	<75 kW/cyl	Gas	124.6	7009.3	66.7
15	Industrial boilers	Cast iron boilers	Oil	108.3	7117.6	67.7

[a] NO_2 basis
[b] Power output
[c] Includes both distillate oil and gasoline
[d] Based on percent of total stationary source NO_x emissions


See Table D-5 for fuel designations
Control factors for NO$_x$ (C$_1$), SO$_x$ (C$_2$) and particulate (C$_3$)
Effluent stream
1 = flue gas
2 = flyash
3 = hopper ash
Sector title
Emission of indicated pollutants in megagrams (metric tonnes) per year
Equipment type
Upper and lower ranges of POM estimates

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FUEL -CNTRL FAC- EFF                                       POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1    2    3  STR     NOX        SOX        HC         CO        PART                 SULFAT     POM HI     POM LO

             SECTOR     1 - UTILITY BOILERS                       EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
   2            .65   1   .72160+06  .34752+07  .22566+04  .29389+05  .16476+07            .44045+05  .31622+03  .25297+01
   2            .65   2                                               .30598+07
   3            .65   1   .43560+06  .26700+07  .13422+04  .17791+05  .97297+06            .34087+05  .19089+03  .15271+01
   3            .65   2                                               .18069+07
   4            .65   1   .23898+06  .83702+06  .74734+03  .97328+04  .51599+06            .12716+05  .10472+03  .85778+00
   4            .65   2                                               .95827+06
   5            .65   1   .12985+05  .17130+05  .43460+03  .14363+04  .41552+05            .15968+03  .63870+01  .51096-01
   5            .65   2                                               .77168+05
   6  .01       .25   1   .29568+05  .10894+06  .16856+03  .16856+04  .44835+04            .50614+04  .16871+00  .16871+00
   6  .01       .25   2                                               .14945+04
   7  .01       .25   1   .74222+05  .23714+06  .42312+03  .42312+04  .11254+05            .63526+04  .42351+00  .42351+00
   7  .01       .25   2                                               .37515+04
   8  .01       .25   1   .95946+05  .15328+06  .54696+03  .54696+04  .14548+05            .41059+04  .54746+00  .54746+00
   8  .01       .25   2                                               .48495+04
   9  .01             1   .54309+04  .39060+04  .21600+03  .55800+03  .21600+03            .10846+03  .30988-01  .30988-01
  10  .06             1   .13795+06  .34020+03  .97524+03  .82782+04  .48762+04                       .31041+02  .35141+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS              .17523+07  .75830+07  .71307+04  .78521+05  .32135+07            .10664+06  .65043+03  .64678+01
  2 FLYASH COLLECTN                                                   .59123+07

             SECTOR     1 - UTILITY BOILERS                       EQUIPMENT TYPE  102 - WALL FIRED BOILER
   2            .65   1   .48650+06  .20038+07  .13012+04  .33135+05  .90617+06            .25396+05  .18243+03  .60234+00
   2            .65   2                                               .16829+07
   3            .65   1   .29370+06  .15406+07  .78604+03  .20017+05  .53551+06            .19669+05  .11015+03  .86387+00
   3            .65   2                                               .99452+06
   4            .65   1   .16118+06  .48256+06  .43086+03  .10972+05  .28375+06            .73313+04  .60378+02  .19945+00
   4            .65   2                                               .52697+06
   5            .65   1   .38830+04  .35552+04  .90200+02  .29810+04  .86240+04            .33140+02  .13256+01  .43792-02
   5            .65   2                                               .16016+05
   6  .05       .25   1   .80083+05  .18894+06  .16856+03  .26068+04  .44835+04            .50614+04  .16871+00  .16871+00
   6  .05       .25   2                                               .14945+04
   7  .05       .25   1   .15113+06  .23763+06  .42398+03  .65569+04  .11277+05            .63655+04  .42437+00  .42437+00
   7  .05       .25   2                                               .37591+04
   8  .05       .25   1   .19527+06  .15352+06  .54782+03  .84721+04  .14571+05            .41124+04  .54882+00  .54832+00
   8  .05       .25   2                                               .48571+04
   9  .05             1   .51806+05  .18336+05  .10140+04  .26195+04  .10140+04            .50915+03  .14547+00  .14547-02
  10  .12             1   .64680+06  .73590+03  .21096+04  .28455+05  .10548+05                       .67146+02  .76014+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS              .20505+07  .46297+07  .60722+04  .11313+06  .17759+07            .68478+05  .42261+03  .30730+01
  2 FLYASH COLLECTN                                                   .32305+07

             SECTOR     1 - UTILITY BOILERS                       EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
   2            .65   1   .13602+06  .56022+06  .36378+03  .36378+04  .25334+06            .71002+04  .50976+02  .16848+00
   2            .65   2                                               .47049+06
   3            .65   1   .81995+05  .42983+06  .21930+03  .21930+04  .14940+06            .54875+04  .30730+02  .10152+00
   3            .65   2                                               .27747+06
   4            .65   1   .45017+05  .13483+06  .12040+03  .12040+04  .79292+05            .20487+04  .16871+02  .55736-01
   4            .65   2                                               .14726+06
```

Figure B-2. Sample Emission Listing

Table B-5. Fuel Type Codes

1. Anthracite
2. Eastern Bituminous
3. Central Bituminous
4. Western Bituminous
5. Lignite
6. High Sulfur Residual Oil
7. Medium Sulfur Residual Oil
8. Low Sulfur Residual Oil
9. Distillate Oil
10. Natural Gas
11. Process Gas
12. Gasoline
13. Processed Material[a]
14. Coal (Bituminous _or_ Lignite)
15. Residual Oil
16. Oil (Residual _or_ Distillate)
17. Dual Fuel (Oil and Gas)

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[a] Emission factors for industrial process heating are typically in units of "Grams of Pollutant per Gram of Product Produced." The corresponding "fuel consumption" then has units of "grams of product processed." In this way, all emissions can be calculated as ("fuel consumption") x (emission factor).

Table B-6. Trace Specie Emissions by Equipment Type and Fuel -- 1977

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1    2    3  STR        NOX        SOX         HC         CO       PART    EXAJ[a]     SULFAT     POM HI     POM LO


            SECTOR    1 - UTILITY BOILERS                EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
   2       .01       1  .71500+03  .41030+04  .16016+02  .37180+02  .52624+04  .28600+01  .47985+02  .34450+00  .27560-02
   3       .01       1  .45700+03  .33460+04  .10237+02  .23764+02  .32904+04  .18280+01  .39320+02  .22019+00  .17615-02
   4       .01       1  .23700+03  .99423+03  .53088+01  .12324+02  .16495+04  .94800+00  .13866+02  .11419+00  .91354-03
   5                 1  .13300+02  .22680+02  .57400+00  .18900+01  .17010+03  .70000-01  .21080+00  .84319-02  .67455-04
   6                 1  .23760+02  .19008+03  .39600+01  .17820+01  .59400+01  .19800+00  .51108+01  .17036-03  .17036-03
   7                 1  .59520+02  .23808+03  .99200+01  .44640+01  .14880+02  .49600+00  .64014+01  .42676-03  .42676-03
   8                 1  .76920+02  .15384+03  .12820+02  .57690+01  .19230+02  .64100+00  .41364+01  .55152-03  .55152-03
   9                 1  .43200+01  .38880+01  .21600+00  .57600+00  .21600+00  .36000-01  .10841+00  .30974-04  .30974-04
  10  .01            1  .56507+02  .21480+00  .64440+00  .50120+01  .30788+01  .71600+00             .19590-01  .22178-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS           .16433+04  .90520+04  .59696+02  .92761+02  .10416+05  .77930+01  .11714+03  .70809+00  .69000-02

            SECTOR    1 - UTILITY BOILERS                EQUIPMENT TYPE  102 - WALL FIRED BOILER
   2  .01  .01       1  .37857+03  .15402+04  .59304+01  .32829+02  .13661+04  .10590+01  .17768+02  .12756+00  .42141-03
   3  .01  .01       1  .23022+03  .11979+04  .36064+01  .19964+02  .81144+03  .64400+00  .13852+02  .77574-01  .25627-03
   4  .01  .01       1  .12548+03  .37159+03  .19656+01  .10881+02  .42822+03  .35100+00  .51340+01  .42280-01  .13968-03
   5                 1  .21000+01  .19440+01  .49200-01  .16200+00  .14580+02  .60000-02  .18068-01  .72274-03  .23876-05
   6  .09            1  .34215+02  .19008+03  .39600+01  .25740+01  .59400+01  .19800+00  .51108+01  .17036-03  .17036-03
   7  .09            1  .85884+02  .23856+03  .99400+01  .64610+01  .14910+02  .49700+00  .64143+01  .42762-03  .42762-03
   8  .09            1  .11077+03  .15384+03  .12820+02  .83330+01  .19230+02  .64100+00  .41364+01  .55152-03  .55152-03
   9                 1  .32300+02  .18360+02  .10200+01  .27200+01  .10200+01  .17000+00  .51194+00  .14627-03  .14627-05
  10  .04            1  .20908+03  .46500+00  .13950+01  .18600+02  .66650+01  .15500+01             .42409-01  .48010-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS           .12086+04  .37130+04  .40687+02  .10252+03  .26681+04  .51160+01  .52946+02  .29184+00  .24508-02

            SECTOR    1 - UTILITY BOILERS                EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
   2  .20  .01       1  .17774+03  .70999+03  .25760+01  .32200+01  .88780+03  .46000+00  .77178+01  .55410-01  .18305-03
   3  .20  .01       1  .13447+03  .68518+03  .19488+01  .24960+01  .65772+03  .34800+00  .74855+01  .41919-01  .13848-03
   4  .20  .01       1  .58733+02  .17144+03  .85120+00  .10640+01  .27816+03  .15200+00  .22233+01  .18309-01  .60486-04
   5                 1  .45600+01  .38880+01  .98400-01  .32400+00  .29160+02  .12000-01  .36137-01  .14455-02  .47752-05
   6  .26            1  .11883+02  .76800+02  .16000+01  .96000+00  .24000+01  .80000-01  .20650+01  .68832-04  .68832-04
   7  .26            1  .29708+02  .96000+02  .40000+01  .24000+01  .60000+01  .20000+00  .25612+01  .17208-03  .17208-03
   8  .26            1  .38472+02  .62160+02  .51800+01  .31080+01  .77700+01  .25900+00  .16713+01  .22284-03  .22284-03
   9                 1  .30000+01  .16200+01  .90000-01  .24000+00  .90000-01  .15000-01  .45171-01  .12906-04  .12906-04
  10  .11            1  .16239+03  .23910+00  .71730+00  .87670+01  .34271+01  .79700+00             .21806-01  .24687-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS           .62096+03  .18073+04  .17062+02  .22519+02  .18725+04  .23230+01  .23825+02  .13937+00  .11103-02

            SECTOR    1 - UTILITY BOILERS                EQUIPMENT TYPE  104 - CYCLONE BOILER
   2                 1  .96850+02  .13112+03  .83440+00  .59600+00  .13440+03  .14900+00  .24999+01  .27371-03  .27371-03
   3                 1  .78650+03  .13552+04  .67760+01  .48400+01  .10672+04  .12100+01  .26027+02  .22227-02  .22227-02
   5                 1  .41280+02  .41796+02  .10578+01  .34830+01  .26445+03  .12900+00  .38847+00  .23697-03  .23697-03
   6                 1  .27500+01  .10780+02  .66000-01  .17600+00  .33000+00  .11000-01  .28393+00  .94644-05  .94644-05
   7                 1  .65000+01  .12740+02  .15600+00  .41600+00  .78000+00  .26000-01  .33556+00  .22370-04  .22370-04
   8                 1  .87500+01  .85750+01  .21000+00  .56000+00  .10500+01  .35000-01  .22586+00  .30114-04  .30114-04
  10                 1  .14250+02  .17100-01  .34200+00  .91200+00  .24510+00  .57000-01             .15596-02  .17655-04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
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[a] EXAJ = Annual fuel consumption in exajoules (10^{18} Joules)

Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                                   POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR     NOX        SOX        HC         CO         PART       EXAJ       SULFAT     POM HI     POM LO

  1 FLUE GAS           .95688+03  .15602+04  .94422+01  .10983+02  .14685+04  .16170+01  .29761+02  .43549-02  .28130-02

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
  1                1   .31620+02  .37332+02  .30600+00  .17340+01  .37026+03  .10200+00  .48268+00  .11190-04  .11190-04
  2                1   .32960+02  .12154+03  .19570+01  .43260+01  .21836+03  .10300+00  .17281+01  .11299-04  .11299-04
  3                1   .32960+02  .15450+03  .19570+01  .43460+01  .21321+03  .10300+00  .22155+01  .11299-04  .11299-04
  5                1   .25600+01  .25920+01  .20800+00  .43200+00  .19440+02  .80000-02  .24091-01  .87761-06  .87761-06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .10010+03  .31596+03  .44280+01  .10818+02  .82127+03  .31600+00  .44504+01  .34666-04  .34666-04

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  106 - FRONT WALL FIRING, WET
  2                1   .36975+03  .60465+03  .24360+01  .34800+01  .11243+04  .43500+00
  3                1   .22355+03  .46288+03  .14728+01  .21040+01  .66276+03  .26300+00
  4                1   .12240+03  .14544+03  .80640+00  .11520+01  .35136+03  .14400+00
  5                1   .22800+01             .49200-01  .16200+00  .14580+02  .60000-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .71798+03  .12130+04  .47644+01  .68980+01  .21510+04  .84800+00

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  107 - HORIZONTALLY OPPOSED,WET
  2                1   .10455+03  .17097+03  .68880+00  .98400+00  .31734+03  .12300+00
  3                1   .62900+02  .13024+03  .41440+00  .59200+00  .18648+03  .74000-01
  4                1   .34850+02  .41410+02  .22960+00  .32800+00  .10004+03  .41000-01
  5                1   .41800+01             .90200-01  .29700+00  .26730+02  .11000-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .20648+03  .34262+03  .14230+01  .22010+01  .63059+03  .24900+00


SECTOR    1 TOTAL
                       .54543+04  .18004+05  .13750+03  .24870+03  .20028+05  .18262+02  .22812+03  .11437+01  .13309-01

  BY FUEL --
 1 ANTHRACITE          .31620+02  .37332+02  .30600+00  .17340+01  .37026+03  .10200+00  .48268+00  .11190-04  .11190-04
 2 EASTERN BITUMIN.    .18754+04  .73815+04  .30439+02  .82615+02  .93087+04  .51890+01  .77698+02  .52776+00  .36455-02
 3 CENTRAL BITUMIN.    .19276+04  .73318+04  .26412+02  .58026+02  .68892+04  .44700+01  .88901+02  .34192+00  .43903-02
 4 WESTERN BITUMIN.    .57846+03  .17241+04  .91616+01  .25749+02  .28073+04  .16360+01  .21223+02  .17478+00  .11137-02
 5 LIGNITE             .70260+02  .72900+02  .21268+01  .67500+01  .53904+03  .24200+00  .67756+00  .10848-01  .31246-03
 6 HIGH S RES. OIL     .72609+02  .46774+03  .95860+01  .54920+01  .14610+02  .48700+00  .12570+02  .41901-03  .41901-03
 7 MED  S RES. OIL     .18161+03  .58538+03  .24016+02  .13741+02  .36570+02  .12190+01  .15732+02  .10488-02  .10488-02
 8 LOW  S RES. OIL     .23491+03  .37841+03  .31030+02  .17770+02  .47280+02  .15760+01  .10170+02  .13560-02  .13560-02
 9 DISTILLATE OIL      .39620+02  .23868+02  .13260+01  .35360+01  .13260+01  .22100+00  .66552+00  .19015-03  .45343-04
10 NATURAL GAS         .44223+03  .93600+00  .30987+01  .33291+02  .13416+02  .31200+01             .85365-01  .96640-03

  BY EFFLUENT STREAMS --
 1 FLUE GAS            .54543+04  .18004+05  .13750+03  .24870+03  .20028+05  .18262+02  .22812+03  .11437+01  .13309-01

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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                    POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR   NOX        SOX        HC         CO        PART       EXAJ      SULFAT     POM HI     POM LO

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  201 - PKG WALLFIRED WT 29-73MW
  9              1  .18600+02  .10044+02  .55800+00  .14880+01  .55800+00  .93000-01  .28006+00  .11202-03  .11322-03
 10              1  .73080+02  .18270+00  .54810+00  .73080+01  .26187+01  .60900+00             .16663-01  .18863-03
 11              1  .10200+02  .25500-01  .76500-01  .10200+01  .36550+00  .85000-01             .23257-02  .26328-04
 14              1  .34800+02  .17632+03  .64960+00  .27840+01  .14616+03  .11600+00  .19462+01  .13973-03  .14123-03
 15              1  .72400+02  .17376+03  .72400+01  .47060+01  .10860+02  .36200+00  .46720+01  .43605-03  .44072-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .20908+03  .36033+03  .90722+01  .17306+02  .16056+03  .12650+01  .68983+01  .19676-01  .91014-03

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  202 - PKG STOKER W-T   29-73MW
 14              1  .24380+02  .16536+03  .20140+01  .43460+01  .18126+03  .10600+00  .17784+01  .12449-03  .12905-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .24380+02  .16536+03  .20140+01  .43460+01  .18126+03  .10600+00  .17784+01  .12449-03  .12905-03

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29MW
  9              1  .61600+01  .17136+02  .64960-01  .32480+00  .96320+00  .11200+00  .33728+00  .13491-03  .13106-03
 10              1  .66540+02  .33270+00  .37706+01  .22180+02  .95374+00  .11090+01  .28626+02  .30343-01  .34351-03
 11              1  .51000+01  .25500-01  .28900+00  .17000+01  .73100-01  .85000-01             .23257-02  .26328-04
 14              1  .23040+02                                   .90720+02  .72000-01
 15              1  .54240+02  .15255+03  .15255+01  .47460+00  .94920+01  .33900+00  .43751+01  .40835-03  .39668-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .15508+03  .17004+03  .56501+01  .24679+02  .10220+03  .17170+01  .33338+02  .33212-01  .89757-03

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29MW
  9              1  .88800+01  .12950+02  .14208+01  .23680+00  .17760+01  .14800+00  .44569+00  .18910+01  .14389-02
 10              1  .21600+02  .16200+00  .12420+01  .10800+02  .21060+01  .54000+00             .14775+02  .15030-03
 11              1  .44000+00                                   .42900-01  .11000-01             .30097+00  .34072-05
 15              1  .26100+02  .78300+02  .43500+01  .24360+00  .48720+01  .17400+00  .22456+01  .22232+01  .16917-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .57020+02  .91412+02  .70128+01  .11280+02  .87969+01  .87300+00  .26913+01  .19190+02  .32844-02

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29MW
  9              1  .80400+01  .11725+02  .12864+01  .21440+00  .16080+01  .13400+00  .40353+00  .17121+01  .13028-02
 10              1  .19960+02  .14970+00  .11477+01  .99800+01  .19461+01  .49900+00             .13889-03  .13889-03
 11              1  .44000+00                                   .42900-01  .11000-01             .30617-05  .30617-05
 15              1  .16800+02  .50400+02  .28000+01  .15680+00  .31360+01  .11200+00  .14455+01  .14310+01  .10889-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .45240+02  .62275+02  .52341+01  .10351+02  .67330+01  .75600+00  .18490+01  .31433+01  .25337-02

        SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  206 - STOKER WATER TUBE  <29MW
  1              1  .13500+01  .17400+01  .95000-01  .45000+00  .15450+02  .50000-02  .23661-01  .58722-05  .20262-03
 14              1  .80270+02  .56189+03  .66310+01  .31410+02  .72243+03  .34900+00  .58555+01  .40988-03  .14143-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .81620+02  .56363+03  .67260+01  .31860+02  .73788+03  .35400+00  .58791+01  .41575-03  .14346-01
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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR    NOX        SOX        HC         CO         PART       EXAJ       SULFAT     POM HI     POM LO


         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  208 - CAST IRON BOILERS
  9               1  .23664+02  .37584+02  .33408+01  .55680+00  .41760+01  .34800+00  .10480+01  .54494-02  .51800-02
 10               1  .91728+02  .52920+00  .40572+01  .35280+02  .68796+01  .17640+01             .49099-03  .49099-03
 14               1  .14550+02  .11058+03  .55290+01  .21340+02  .31428+03  .97000-01  .16274+01  .77199-01
 15               1  .84600+02  .22560+03  .11750+02  .65800+00  .13160+02  .47000+00  .60658+01  .69959-02  .69959-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .21454+03  .37429+03  .24677+02  .57835+02  .33850+03  .26790+01  .87412+01  .90136-01  .12667-01

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  209 - STOKER FIRETUBE     <29MW
  1               1  .21600+01  .27840+01  .45600+00  .72000+00  .24880+02  .80000-02  .37858-01  .26810-01  .32454-03
 14               1  .23460+02  .16422+03  .58140+01  .91800+01  .21114+03  .10200+00  .17113+01  .34183+00  .41379-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .25620+02  .16700+03  .62700+01  .99000+01  .23602+03  .11000+00  .17492+01  .36864+00  .44625-02

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  210 - HRT BOILER          <29MW
  9               1  .52800+01  .77000+01  .84480+00  .14080+00  .10560+01  .88000-01  .26500+00  .11244+01  .85558-03
 10               1  .11880+02  .89100-01  .68310+00  .59400+01  .11583+01  .29700+00             .81261-02  .91994-04
 15               1  .10200+02  .30600+02  .17000+01  .95200-01  .19040+01  .68000-01  .87761+00  .86883+00  .66113-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .27360+02  .38389+02  .32279+01  .61760+01  .41183+01  .45300+00  .11426+01  .20013+01  .16087-02

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
  1               1  .43380+01  .91098+01  .10363+01  .33740+01  .88929+02  .24100-01  .11405+00  .19180-01  .19180-01
  9               1  .77896+02  .15023+03  .13354+02  .41730+02  .10572+02  .13910+01  .41889+01  .20705-01  .20705-01
 10               1  .82800+02  .62100+00  .47610+01  .17802+02  .16560+02  .20700+01             .57616-03  .57616-03
 14               1  .28350+01  .21546+02  .10773+01  .41580+01  .61236+02  .18900-01  .31710+00  .15042-01  .15042-01
 15               1  .17520+02  .52560+02  .27375+01  .16425+01  .90885+01  .10950+00  .14132+01  .16299+00  .16299-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .18539+03  .23406+03  .22966+02  .68706+02  .18639+03  .36135+01  .60332+01  .21849+00  .57133-01

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  221 - TANGENTIAL BOILERS >73MW
  2               1  .19240+02  .89540+02  .41440+00  .88800+00  .13616+03  .74000-01  .12416+01  .89137-02  .71310-04
  3               1  .11700+02  .69300+02  .25200+00  .54000+00  .81000+02  .45000-01  .96795+00  .54205-02  .43364-04
  4               1  .65000+01  .22000+02  .14000+00  .30000+00  .43500+02  .25000-01  .36567+00  .30114-02  .24091-04
  5               1  .22000+00  .32400+00  .82000-02  .27000-01  .24300+01  .10000-02  .30114-02  .12046-03  .96365-06
  6               1  .34000+01  .19200+02  .40000+00  .18000+00  .60000+00  .20000-01  .51624+00  .17208-04  .17208-04
  7               1  .86700+01  .24480+02  .10200+01  .45900+00  .15300+01  .51000-01  .65821+00  .43880-04  .43880-04
  8               1  .11050+02  .15600+02  .13000+01  .58500+00  .19500+01  .65000-01  .41945+00  .55926-04  .55926-04
  9               1  .74800+01  .47520+01  .26400+00  .70400+00  .26400+00  .44000-01  .13250+00  .37858-04  .37858-04
 10               1  .43780+02  .11940+00  .35820+00  .27860+01  .17114+01  .39800+00             .10890-01  .12328-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .11204+03  .24532+03  .41568+01  .64690+01  .26915+03  .72300+00  .43046+01  .28511-01  .41788-03

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  222 - WALL FIRED - DRY    >73MW
  2               1  .90000+01  .45600+02  .16800+00  .72000+00  .38700+02  .30000-01  .50333+00  .36137-02  .11938-04
  3               1  .51000+01  .32810+02  .95200-01  .40800+00  .21420+02  .17000-01  .36567+00  .20478-02  .67649-05
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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                            POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1    2   3  STR      NOX        SOX         HC         CO        PART        EXAJ       SULFAT      POM HI      POM LO

  4                1    .30000+01  .11000+02  .56000-01  .24000+00  .12200+02  .10000-01  .14627+00  .12046-02  .39793-05
  5                1    .19000+00  .16200+00  .41000-02  .13500-01  .12150+01  .50000-03  .15057-02  .60228-04  .19897-06
  6                1    .40000+01  .19200+02  .40000+00  .26000+00  .60000+00  .20000-01  .51624+00  .17208-04  .17208-04
  7                1    .10200+02  .24480+02  .10200+01  .66300+00  .15300+01  .51000-01  .65821+00  .43880-04  .43880-04
  8                1    .13000+02  .15600+02  .13000+01  .84500+00  .19500+01  .65000-01  .41945+00  .55926-04  .55926-04
  9                1    .41400+02  .22356+02  .12420+01  .33120+01  .12420+01  .20700+00  .62336+00  .17810-03  .17810-05
 10                1    .10344+03  .25860+00  .77580+00  .10344+02  .37066+01  .86200+00              .23585-01  .26700-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .18933+03  .17147+03  .50611+01  .16805+02  .82564+02  .12625+01  .32340+01  .30806-01  .40868-03

          SECTOR    2 - INDUSTRIAL BOILERS                  EQUIPMENT TYPE  223 - OPPOSED WALL - DRY >73MW
  2                1    .43200+01  .14040+02  .50400-01  .63000-01  .17370+02  .90000-02  .15100+00  .10841-02  .35814-05
  3                1    .28800+01  .11940+02  .33600-01  .42000-01  .11340+02  .60000-02  .12906+00  .72274-03  .23876-05
  4                1    .14400+01  .34200+01  .16800-01  .21000-01  .54900+01  .30000-02  .43880-01  .36137-03  .11938-05
  5                1    .15200+00  .12960+00  .32800-02  .10800-01  .97200+00  .40000-03  .12046-02  .48182-04  .15917-06
  6                1    .16000+01  .76800+01  .16000+00  .96000-01  .24000+00  .80000-02  .20650+00  .68832-05  .68832-05
  7                1    .40000+01  .96000+01  .40000+00  .24000+00  .60000+00  .20000-01  .25812+00  .17208-04  .17208-04
  8                1    .54000+01  .64800+01  .54000+00  .32400+00  .81000+00  .27000-01  .17423+00  .23231-04  .23231-04
  9                1    .40000+01  .21600+01  .12000+00  .32000+00  .12000+00  .20000-01  .60228-01  .17208-04  .17208-04
 10                1    .10189+03  .13290+00  .39870+00  .48730+01  .19049+01  .44300+00              .12121-01  .13722-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .12568+03  .55582+02  .17228+01  .59898+01  .38847+02  .53640+00  .10242+01  .14402-01  .20907-03

          SECTOR    2 - INDUSTRIAL BOILERS                  EQUIPMENT TYPE  224 - CYCLONE  BOILERS   >73MW
  2                1    .32500+01  .44000+01  .28000-01  .20000-01  .45100+01  .50000-02  .83889-01  .91848-05  .91848-05
  3                1    .24050+02  .41440+02  .20720+00  .14800+00  .32634+02  .37000-01  .79587+00  .67967-04  .67967-04
  5                1    .96000+00  .97200+00  .24600-01  .81000-01  .61500+01  .30000-02  .90342-02  .55109-05  .55109-05
  6                1    .25000+00  .98000+00  .60000-02  .16000-01  .30000-01  .10000-02  .25812-01  .86040-06  .86040-06
  7                1    .75000+00  .14700+01  .18000-01  .48000-01  .90000-01  .30000-02  .38718-01  .25812-05  .25812-05
  8                1    .10000+01  .98000+00  .24000-01  .64000-01  .12000+00  .40000-02  .25812-01  .34416-05  .34416-05
 10                1    .52500+01  .63000-02  .12600+00  .33600+00  .90300-01  .21000-01              .57458-05  .65046-05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .35510+02  .50248+02  .43380+00  .71300+00  .43624+02  .74000-01  .97914+00  .66412-03  .96051-04

          SECTOR    2 - INDUSTRIAL BOILERS                  EQUIPMENT TYPE  225 - VERTICAL/STOKER    >73MW
  1                1    .93000+00  .10980+01  .90000-02  .51000-01  .10710+02  .30000-02  .14197-01  .32910-06  .32910-06
  2                1    .96000+00  .35400+01  .57000-01  .12600+00  .63600+01  .30000-02  .50333-01  .32910-06  .32910-06
  3                1    .96000+00  .45000+01  .57000-01  .12600+00  .62100+01  .30000-02  .64530-01  .32910-06  .32910-06
  5                1    .64000-01  .64800-01  .52000-02  .10800-01  .48600+00  .20000-03  .60228-03  .21940-07  .21940-07
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .29140+01  .92028+01  .12820+00  .31380+00  .23766+02  .92000-02  .12966+00  .10092-05  .10092-05

          SECTOR    2 - INDUSTRIAL BOILERS                  EQUIPMENT TYPE  226 - WALL FIRED - WET   >73MW
  2                1    .11050+02  .18070+02  .72800-01  .10400+00  .33540+02  .13000-01
  3                1    .68000+01  .14160+02  .44800-01  .64000-01  .20160+02  .80000-02
  4                1    .34000+01  .40400+01  .22400-01  .32000-01  .97600+01  .40000-02
  5                1    .19000+00             .41000-02  .13500-01  .12150+01  .50000-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .21440+02  .36270+02  .14410+00  .21350+00  .64675+02  .25500-01
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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                         POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR     NOX        SOX        HC         CO        PART       EXAJ      SULFAT     POM HI     POM LO


       SECTOR    2 - INDUSTRIAL BOILERS                   EQUIPMENT TYPE  227 - OPPOSED WALL - WET >73MW
  2               1   .34000+01  .55600+01  .22400-01  .32000-01  .10320+02  .40000-02
  3               1   .17000+01  .35400+01  .11200-01  .16000-01  .50400+01  .20000-02
  4               1   .85000+00  .10100+01  .56000-02  .80000-02  .24400+01  .10000-02
  5               1   .22800+00             .49200-02  .16200-01  .14580+01  .60000-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .61780+01  .10110+02  .44120-01  .72200-01  .19258+02  .76000-02

SECTOR    2 TOTAL
                      .15184+04  .28050+04  .10454+03  .27302+03  .25043+04  .14565+02  .79772+02  .25140+02  .99105-01

   BY FUEL --
  1 ANTHRACITE        .87780+01  .14732+02  .15963+01  .45950+01  .13997+03  .40100-01  .18976+00  .45997-01  .19708-01
  2 EASTERN BITUMIN.  .51220+02  .18075+03  .81300+00  .19530+01  .24696+03  .13800+00  .20301+01  .13621-01  .96343-04
  3 CENTRAL BITUMIN.  .53190+02  .17769+03  .70100+00  .13440+01  .17780+03  .11800+00  .23231+01  .82593-02  .12081-03
  4 WESTERN BITUMIN.  .15190+02  .41470+02  .24080+00  .60100+00  .73390+02  .43000-01  .55582+00  .45773-02  .29264-04
  5 LIGNITE           .20040+01  .16524+01  .54400-01  .17280+00  .13926+02  .62000-02  .15358-01  .23440-03  .68546-05
  6 HIGH S RES. OIL   .92500+01  .47060+02  .96600+00  .55200+00  .14700+01  .49000-01  .12648+01  .42160-04  .42160-04
  7 MED  S RES. OIL   .23620+02  .60030+02  .24580+01  .14100+01  .37500+01  .12500+00  .16132+01  .10755-03  .10755-03
  8 LOW  S RES. OIL   .30450+02  .38660+02  .31640+01  .18180+01  .48300+01  .16100+00  .10389+01  .13852-03  .13852-03
  9 DISTILLATE OIL    .20140+03  .27663+03  .22495+02  .49026+02  .22395+02  .25850+01  .77845+01  .47541+01  .29783-01
 10 NATURAL GAS       .62195+03  .25836+01  .17868+02  .12763+03  .39636+02  .86120+01  .28626+02  .14878+02  .25145-02
 11 PROCESS GAS       .16180+02  .51000-01  .36550+00  .27400+01  .52440+00  .19200+00             .30562+00  .59125-04
 14 BIT/LIG COAL      .20333+03  .11999+04  .21715+02  .73218+02  .17272+04  .86090+00  .13236+02  .43474+00  .33593-01
 15 RESIDUAL OIL      .28186+03  .76377+03  .32103+02  .79767+01  .52512+02  .16345+01  .21095+02  .46969+01  .12905-01

   BY EFFLUENT STREAMS --
  1 FLUE GAS          .15184+04  .28050+04  .10454+03  .27302+03  .25043+04  .14565+02  .79772+02  .25140+02  .99105-01

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       SECTOR    3 - WARM AIR FURNACES                    EQUIPMENT TYPE  301 - WARM AIR CENTRAL FURNACE
 10               1   .80500+02  .59800+00  .78200+01  .23000+02  .92000+01  .23000+01             .75199-03  .75199-03
 16               1   .41500+02  .17928+03  .78020+01  .41500+02  .12616+02  .16600+01  .49989+01  .12926-01  .12926-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .12200+03  .17988+03  .15622+02  .64500+02  .21816+02  .39600+01  .49989+01  .13678-01  .13678-01

       SECTOR    3 - WARM AIR FURNACES                    EQUIPMENT TYPE  302 - WARM AIR SPACE HEATER
 10               1   .19950+02  .14820+00  .19380+01  .57000+01  .22800+01  .57000+00             .15596-01  .15645-01
 16               1   .10500+02  .45360+02  .19740+01  .10500+02  .31920+01  .42000+00  .12648+01  .32704-02  .32704-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .30450+02  .45508+02  .39120+01  .16200+02  .54720+01  .99000+00  .12648+01  .18866-01  .18915-01

       SECTOR    3 - WARM AIR FURNACES                    EQUIPMENT TYPE  303 - MISCELLANEOUS COMBUSTION
 10               1   .38500+02  .28600+00  .37400+01  .11000+02  .44000+01  .11000+01
 16               1   .19750+02  .85320+02  .37130+01  .19750+02  .60040+01  .79000+00  .23790+01  .61514-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .58250+02  .85606+02  .74530+01  .30750+02  .10404+02  .18900+01  .23790+01  .61514-02
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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                 POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1    2   3  STR      NOX       SOX        HC         CO        PART       EXAJ      SULFAT     POM HI     POM LO

SECTOR    3 TOTAL
                        .21070+03  .31099+03  .26987+02  .11145+03  .37692+02  .68400+01  .86427+01  .38695-01  .32593-01

  BY FUEL --
 10 NATURAL GAS         .13895+03  .10322+01  .13498+02  .39700+02  .15880+02  .39700+01             .16348-01  .16397-01
 16 OIL                 .71750+02  .30996+03  .13489+02  .71750+02  .21812+02  .28700+01  .86427+01  .22348-01  .16196-01

  BY EFFLUENT STREAMS --
 1 FLUE GAS             .21070+03  .31099+03  .26987+02  .11145+03  .37692+02  .68400+01  .86427+01  .38695-01  .32593-01

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          SECTOR    4 - GAS TURBINES                        EQUIPMENT TYPE  401 - SIMPLE CYCLE    >15 MJ/S
 9                 1    .57491+02  .17120+01  .64000+00  .48000+01  .25600+01  .16000+00
 10                1    .24638+02  .28600+00  .26000+00  .28600+01  .78000+00  .13000+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS             .82129+02  .19980+01  .90000+00  .76600+01  .33400+01  .29000+00

          SECTOR    4 - GAS TURBINES                        EQUIPMENT TYPE  404 - SIMPLE CYCLE 3.7-15 MJ/S
 9                 1    .77552+02  .39590+01  .14800+01  .44400+02  .59200+01  .37000+00
 10                1    .37107+02  .68200+00  .12400+01  .15500+02  .18600+01  .31000+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS             .11466+03  .46410+01  .27200+01  .59900+02  .77800+01  .68000+00

          SECTOR    4 - GAS TURBINES                        EQUIPMENT TYPE  406 - SIMPLE CYCLE   <3.7 MJ/S
 9                 1    .86236+01  .51360+00  .19200+00  .57600+01  .76800+00  .48000-01
 10                1    .57456+01  .10560+00  .19200+00  .24000+01  .28800+00  .48000-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS             .14369+02  .61920+00  .38400+00  .81600+01  .10560+01  .96000-01

SECTOR    4 TOTAL
                        .21116+03  .72582+01  .40040+01  .75720+02  .12176+02  .10660+01

  BY FUEL --
  9 DISTILLATE OIL      .14367+03  .61846+01  .23120+01  .54960+02  .92480+01  .57800+00
 10 NATURAL GAS         .67491+02  .10736+01  .16920+01  .20760+02  .29280+01  .48800+00

  BY EFFLUENT STREAMS --
 1 FLUE GAS             .21116+03  .72582+01  .40040+01  .75720+02  .12176+02  .10660+01

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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       NOX        SOX        HC         CO         PART       EXAJ       SULFAT      POM HI      POM LO


          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  501 - C. I.        >75 KJ/S/CYL
  9               1    .76850+02  .50880+01  .26500+01  .16430+02  .53000+01  .53000-01
 17               1    .72900+02             .18360+02  .17280+02  .54000+01  .54000-01
EQUIPP NT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .14975+03  .50880+01  .21010+02  .33710+02  .10700+02  .10700+00

          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  502 - S. I.        >75 KJ/S/CYL
 10               1    .63000+03  .79200-01  .16560+03  .64800+02  .21600+01  .36000+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .63000+03  .79200-01  .16560+03  .64800+02  .21600+01  .36000+00

          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  503 - C. I. 75KJ/S-75 KJ/S/CYL
  9               1    .18620+03  .13440+02  .29400+02  .78400+02  .14000+02  .14000+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .18620+03  .13440+02  .29400+02  .78400+02  .14000+02  .14000+00

          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  504 - S. I. 75KJ/S-75 KJ/S/CYL
 10               1    .79040+03  .10868+00  .22724+03  .88920+02  .29640+01  .49400+00
 12               1    .22940+02  .49600+00  .12400+02  .37200+03  .62000+00  .31000-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .81334+03  .60468+00  .23964+03  .46092+03  .35840+01  .52500+00

          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  505 - C.I.              <75 KJ/S
  9               1    .41600+02  .30720+01  .92800+01  .23200+02  .16000+01  .32000-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .41600+02  .30720+01  .92800+01  .23200+02  .16000+01  .32000-01

          SECTOR    5 - RECIPROCATING I/C ENGINE         EQUIPMENT TYPE  506 - S. I.             <75 KJ/S
 10               1    .12464+03  .17138-01  .35834+02  .14022+02  .46740+00  .77900-01
 12               1    .39000+02  .24960+01  .21060+03  .62400+04  .31240+01  .15600+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .16364+03  .25131+01  .24643+03  .62540+04  .35874+01  .23390+00

SECTOR    5 TOTAL
                       .19845+04  .24797+02  .71136+03  .69151+04  .35631+02  .13979+01

   BY FUEL --
  9 DISTILLATE OIL     .30465+03  .21600+02  .41330+02  .11803+03  .20900+02  .22500+00
 10 NATURAL GAS        .15450+04  .20502+00  .42867+03  .16774+03  .55914+01  .93190+00
 12 GASOLINE           .61940+02  .29920+01  .22300+03  .66120+04  .37400+01  .18700+00
 17 DUAL (OIL + GAS)   .72900+02             .18360+02  .17280+02  .54000+01  .54000-01

   BY EFFLUENT STREAMS --
  1 FLUE GAS           .19845+04  .24797+02  .71136+03  .69151+04  .35631+02  .13979+01

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Table B-6. (Continued)

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FUEL -CNTRL FAC- EFF                                 POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR  NOX        SOX         HC         CO       PART       EXAJ      SULFAT     POM HI     POM LO

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  601 - CEMENT KILNS
 13            1   .89570+02  .35139+03                        .82680+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .89570+02  .35139+03                        .82680+04

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  602 - GLASS MELTING FURNACES
 13            1   .90200+02  .48400+02  .22000+01  .13200+01  .70400+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .90200+02  .48400+02  .22000+01  .13200+01  .70400+02

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  603 - GLASS ANNEALING LEHRS
 13            1   .43000+00             .21500-01  .43000-01  .21500-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .43000+00             .21500-01  .43000-01  .21500-01

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  604 - COKE OVEN UNDERFIRE
 13            1   .30520+01  .12208+03                        .16568+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .30520+01  .12208+03                        .16568+04

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  605 - STEEL SINTERING MACHINES
 13            1   .16536+02  .22578+02             .69960+03  .31800+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .16536+02  .22578+02             .69960+03  .31800+03

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  606 - OPEN HEARTH FURNCE (OIL)
 13            1   .11284+02  .36400+02  .72800-01  .10920+02  .91000+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .11284+02  .36400+02  .72800-01  .10920+02  .91000+02

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  607 - BRICK + CERAMIC KILNS
 13            1   .47840+01  .11232+02  .83200+00  .20800+01  .13520+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .47840+01  .11232+02  .83200+00  .20800+01  .13520+04

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  608 - CAT CRACKING (FCCU)
 13            1   .55006+02  .38504+03  .17327+03  .10726+05  .19252+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS       .55006+02  .38504+03  .17327+03  .10726+05  .19252+03

          SECTOR    6 - IND. PROCESS COMBUSTION     EQUIPMENT TYPE  609 - REFINERY FLARES
 13            1   .82555+01             .35499+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
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Table B-6. (Continued)

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                                                    POLLUTANTS (GIGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR      NOX        SOX        HC         CO         PART       EXAJ       SULFAT     POM HI     POM LO

  1 FLUE GAS           .82555+01             .35499+01

          SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  611 - IRON + STEEL FLARES
 13               1    .27350+00             .11760+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .27350+00             .11760+00

          SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  612 - REF. HTR.-NAT. DRAFT,GAS
 13               1    .82700+02  .20344+01  .13232+01  .52928+01  .14224+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .82700+02  .20344+01  .13232+01  .52928+01  .14224+02

          SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  613 - REF. HTR.-NAT. DRAFT,OIL
 13               1    .32250+02  .13545+02  .27950+01             .16856+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .32250+02  .13545+02  .27950+01             .16856+02

          SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  614 - REF. HTR.-FOR. DRAFT,GAS
 13               1    .22440+02  .25092+00  .16320+00             .17544+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .22440+02  .25092+00  .16320+00             .17544+01

          SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TY E  615 - REF. HTR.-FOR. DRAFT,OIL
 13               1    .12240+02  .42840+01  .88400+00             .53312+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .12240+02  .42840+01  .88400+00             .53312+01

SECTOR    6 TOTAL
                       .42902+03  .99724+03  .18523+03  .11445+05  .11987+05

   BY FUEL --
 13 PROCESSED MAT'L    .42902+03  .99724+03  .18523+03  .11445+05  .11987+05

   BY EFFLUENT STREAMS --
  1 FLUE GAS           .42902+03' .09724+03  .18523+03  .11445+05  .11987+05

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Table B-6. (Concluded)

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	POLLUTANTS (GIGAGRAMS/YEAR)								
	NOX	SOX	HC	CO	PART	EXAJ	SULFAT	POM HI	POM LO
GRAND TOTAL	.98082+04	.22149+05	.11696+04	.19069+05	.34604+05	.42131+02	.31654+03	.26322+02	.14501+00
BY FUEL --									
1 ANTHRACITE	.40398+02	.52064+02	.19023+01	.63290+01	.51023+03	.14210+00	.67245+00	.46008-01	.19719-01
2 EASTERN BITUMIN.	.19266+04	.75623+04	.31252+02	.84568+02	.95557+04	.53270+01	.79728+02	.54138+00	.37418-02
3 CENTRAL BITUMIN.	.19808+04	.75095+04	.27113+02	.59370+02	.70670+04	.45880+01	.91224+02	.35018+00	.45111-02
4 WESTERN BITUMIN.	.59365+03	.17656+04	.94024+01	.26550+02	.28807+04	.16790+01	.21779+02	.17956+00	.11430-02
5 LIGNITE	.72264+02	.74552+02	.21812+01	.69428+01	.55297+03	.24820+00	.69292+00	.11072-01	.31932-03
6 HIGH S RES. OIL	.81859+02	.51480+03	.10552+02	.60440+01	.16080+02	.53600+00	.13835+02	.46117-03	.46117-03
7 MED S RES. OIL	.20523+03	.64541+03	.26474+02	.15151+02	.40320+02	.13440+01	.17346+02	.11564-02	.11564-02
8 LOW S RES. OIL	.26536+03	.41707+03	.34194+02	.19588+02	.52110+02	.17370+01	.11209+02	.14945-02	.14945-02
9 DISTILLATE OIL	.68934+03	.32829+03	.67463+02	.22555+03	.53809+02	.36090+01	.84500+01	.47543+01	.29829-01
10 NATURAL GAS	.28157+04	.58304+01	.46483+03	.38912+03	.77451+02	.17122+02	.28626+02	.14980+02	.19878-01
11 PROCESS GAS	.16180+02	.51000-01	.36550+00	.27200+01	.52440+00	.19200+00		.30562+00	.59125-04
12 GASOLINE	.61940+02	.29920+01	.22300+03	.66120+04	.37400+01	.18700+00			
13 PROCESSED MAT'L	.42902+03	.99724+03	.18523+03	.11445+05	.11907+05				
14 BIT/LIG COAL	.20333+03	.11999+04	.21715+02	.73218+02	.17272+04	.86090+00	.13236+02	.43474+00	.33593-01
15 RESIDUAL OIL	.28186+03	.76377+03	.32103+02	.79767+01	.52512+02	.16345+01	.21095+02	.46939+01	.12905-01
16 OIL	.71750+02	.30996+03	.13489+02	.71750+02	.21812+02	.28700+01	.86427+01	.22348-01	.16196-01
17 DUAL (OIL + GAS)	.72900+02		.18360+02	.17280+02	.54000+01	.54000-01			

Table B-7. Trace Specie Emissions by Equipment Type and Fuel -- 1977

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FUEL -CNTRL FAC- EFF                                              POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR      BA          BE           B           CR          CO          CU          PB          MN          HG          MO


          SECTOR     1 - UTILITY BOILERS                      EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
  2       .01       1   .55367+00  .44047-01  .29160+01  .36296+00  .93754-01  .10212+01  .50445+00  .13657+01  .19440-01  .20424+00
  2       .01       3   .18456+01  .87972-01  .58320+01  .58074+00  .56228+00  .14272+01  .21655+00  .27314+01  .10766-02  .32605+00
  3       .01       1   .35388+00  .28153-01  .18638+01  .23199+00  .59924-01  .65272+00  .32243+00  .87291+00  .12425-01  .13054+00
  3       .01       3   .11796+01  .56228-01  .37276+01  .37118+00  .35939+00  .91223+00  .13841+00  .17458+01  .68810-03  .20840+00
  4       .01       1   .18352+00  .14600-01  .96656+00  .12031+00  .31077-01  .33850+00  .16721+00  .45269+00  .64437-02  .67700-01
  4       .01       3   .61174+00  .29160-01  .19331+01  .19250+00  .18638+00  .47308+00  .71778-01  .90538+00  .35685-03  .10807+00
  5                 1   .17075+00  .14154-02  .38546-01  .65950-02  .24212-02  .14154-01  .78899-02  .29211-01  .23730-03  .15960-02
  5                 3   .56915+00  .28307-02  .77092-01  .10540-01  .14515-01  .19815-01  .16924-02  .58421-01  .13190-04  .25537-02
  6                 1   .28109-01             .36627-02  .36627-01  .14481-01  .29813-01  .33220-01  .29813-01  .43442-03  .29813-01
  6                 3   .93698-01             .73254-01  .57922-01  .85180-01  .41738-01  .14481-01  .59626-01  .24702-04  .47701-02
  7                 1   .70415-01             .91753-02  .91753-01  .36274-01  .74683-01  .83218-01  .74683-01  .10882-02  .74683-01
  7                 3   .23472+00             .18351+00  .14510+00  .21338+00  .10456+00  .36274-01  .14937+00  .61880-04  .11949-01
  8                 1   .91000-01             .11858-01  .11858+00  .46879-01  .96515-01  .10755+00  .96515-01  .14064-02  .96515-01
  8                 3   .30333+00             .23715+00  .18752+00  .27576+00  .13512+00  .46879-01  .19303+00  .79970-04  .15442-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .14513+01  .88216-01  .58096+01  .96881+00  .28481+00  .22276+01  .12260+01  .29215+01  .41475-01  .60509+00
  3 BOTTM HOPPER ASH    .48378+01  .17619+00  .12064+02  .15455+01  .16969+01  .31138+01  .52606+00  .58431+01  .23013-02  .67724+00

          SECTOR     1 - UTILITY BOILERS                      EQUIPMENT TYPE  102 - WALL FIRED BOILER
  2  .01 .01        1   .20501+00  .16310-01  .10797+01  .13440+00  .34715-01  .37813+00  .18679+00  .50570+00  .71982-02  .75627-01
  2  .01 .01        3   .68337+00  .32574-01  .21595+01  .21503+00  .20820+00  .52847+00  .80182-01  .10114+01  .39863-03  .12073+00
  3  .01 .01        1   .12467+00  .99183-02  .65661+00  .81729-01  .21111-01  .22995+00  .11359+00  .30752+00  .43774-02  .45990-01
  3  .01 .01        3   .41557+00  .19809-01  .13132+01  .13077+00  .12661+00  .32138+00  .48761-01  .61505+00  .24242-03  .73418-01
  4  .01 .01        1   .67950-01  .54058-02  .35787+00  .44545-01  .11506-01  .12533+00  .61910-01  .16761+00  .23858-02  .25066-01
  4  .01 .01        3   .22650+00  .10797-01  .71574+00  .71272-01  .69007-01  .17516+00  .26576-01  .33522+00  .13213-03  .40015-01
  5                 1   .14635-01  .12132-03  .33039-02  .56528-03  .20753-03  .12132-02  .67627-03  .25038-02  .20340-04  .13680-03
  5                 3   .48785-01  .24263-03  .66079-02  .90342-03  .12441-02  .16984-02  .14506-03  .50075-02  .11306-05  .21889-03
  6  .09            1   .28109-01             .36627-02  .36627-01  .14481-01  .29813-01  .33220-01  .29813-01  .43442-03  .29813-01
  6  .09            3   .93698-01             .73254-01  .57922-01  .85180-01  .41738-01  .14481-01  .59626-01  .24702-04  .47701-02
  7  .09            1   .70557-01             .91938-02  .91938-01  .36348-01  .74833-01  .83386-01  .74833-01  .10904-02  .74833-01
  7  .09            3   .23519+00             .18388+00  .14539+00  .21381+00  .10477+00  .36348-01  .14967+00  .62005-04  .11973-01
  8  .09            1   .91000-01             .11858-01  .11858+00  .46879-01  .96515-01  .10755+00  .96515-01  .14064-02  .96515-01
  8  .09            3   .30333+00             .23715+00  .18752+00  .27576+00  .13512+00  .46879-01  .19303+00  .79970-04  .15442-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .60194+00  .31755-01  .21222+01  .50838+00  .16525+00  .93579+00  .58712+00  .11845+01  .16913-01  .34798+00
  3 BOTTM HOPPER ASH    .20065+01  .63422-01  .46893+01  .80881+00  .97981+00  .13083+01  .25337+00  .23690+01  .94098-03  .26657+00

          SECTOR     1 - UTILITY BOILERS                      EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
  2  .20 .01        1   .89051-01  .70845-02  .46900+00  .58378-01  .15079-01  .16425+00  .81136-01  .21966+00  .31267-02  .32850-01
  2  .20 .01        3   .29684+00  .14149-01  .93801+00  .93405-01  .90437-01  .22955+00  .34829-01  .43932+00  .17316-03  .52441-01
  3  .20 .01        1   .67369-01  .53596-02  .35481+00  .44164-01  .11408-01  .12426+00  .61381-01  .16618+00  .23654-02  .24852-01
  3  .20 .01        3   .22456+00  .10704-01  .70962+00  .70663-01  .68417-01  .17366+00  .26349-01  .33236+00  .13100-03  .39673-01
  4  .20 .01        1   .29426-01  .23410-02  .15498+00  .19290-01  .49827-02  .54274-01  .26810-01  .72583-01  .10332-02  .10855-01
  4  .20 .01        3   .98086-01  .46754-02  .30995+00  .30864-01  .29883-01  .75853-01  .11509-01  .14517+00  .57217-04  .17328-01
  5                 1   .29271-01  .24263-03  .66079-02  .11306-02  .41506-03  .24263-02  .13525-02  .50075-02  .40680-04  .27361-03
  5                 3   .97569-01  .48527-03  .13216-01  .18068-02  .24883-02  .33969-02  .29013-03  .10015-01  .22611-05  .43777-03
  6  .26            1   .11357-01             .14799-02  .14799-01  .58507-02  .12046-01  .13422-01  .12046-01  .17552-03  .12046-01
  6  .26            3   .37858-01             .29598-01  .23403-01  .34416-01  .16864-01  .58507-02  .24091-01  .99806-05  .19273-02
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Table B-7. (Continued)

FUEL TYPE	-CNTRL FAC- 1	2	3	EFF STR	BA	BE	B	CR	CO	CU	PB	MN	HG	MO
					POLLUTANTS (GIGAGRAMS/YEAR)									
7	.26			1	.28393-01		.36997-02	.36997-01	.14627-01	.30114-01	.33556-01	.30114-01	.43880-03	.30114-01
7	.26			3	.94644-01		.73994-01	.58507-01	.86040-01	.42160-01	.14627-01	.60228-01	.24952-04	.48182-02
8	.26			1	.36769-01		.47911-02	.47911-01	.18942-01	.38998-01	.43455-01	.38998-01	.56825-03	.38998-01
8	.26			3	.12256+00		.95823-01	.75767-01	.11142+00	.54597-01	.18942-01	.77995-01	.32312-04	.62396-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.29164+00	.15028-01	.99537+00	.22267+00	.71304-01	.42637+00	.26111+00	.84459+00	.77485-02	.14999+00
3 BOTTM HOPPER ASH					.97212+00	.30014-01	.21702+01	.35442+00	.42310+00	.59609+00	.11240+00	.10892+01	.43087-03	.12287+00
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 104 - CYCLONE BOILER						
2				1	.28845-01	.22948-02	.15192+00	.18909-01	.48844-02	.53203-01	.26281-01	.71151-01	.10128-02	.10641-01
2				3	.96150-01	.45831-02	.30383+00	.30255-01	.29294-01	.74356-01	.11282-01	.14230+00	.56087-04	.16986-01
3				1	.23424+00	.18635-01	.12337+01	.15356+00	.39665-01	.43205+00	.21342+00	.57780+00	.82246-02	.86410-01
3				3	.78081+00	.37219-01	.24674+01	.24570+00	.23789+00	.60383+00	.91615-01	.11556+01	.45547-03	.13794+00
5				1	.51466+00	.26083-02	.71035-01	.12154-01	.44619-02	.26083-01	.14540-01	.53831-01	.43731-03	.29413-02
5				3	.10489+01	.52166-02	.14207+00	.19424-01	.26749-01	.36516-01	.31189-02	.10766+00	.24307-04	.47060-02
6				1	.15616-02		.20348-03	.20348-02	.80447-03	.16563-02	.18456-02	.16563-02	.24134-04	.16563-02
6				3	.52054-02		.40697-02	.32179-02	.47342-02	.23188-02	.80447-03	.33125-02	.13723-05	.26500-03
7				1	.56911-02		.48096-03	.48096-02	.19015-02	.39148-02	.43622-02	.39148-02	.57045-04	.39148-02
7				3	.12304-01		.96193-02	.76059-02	.11185-01	.54807-02	.19015-02	.78296-02	.32437-05	.62637-03
8				1	.49688-02		.64745-03	.64745-02	.25597-02	.52699-02	.58722-02	.52699-02	.76791-04	.52699-02
8				3	.16563-01		.12949-01	.10239-01	.15057-01	.73779-02	.25597-02	.10540-01	.43665-05	.84319-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.58797+00	.23538-01	.14580+01	.19794+00	.54277-01	.52218+00	.26632+00	.71362+00	.98326-02	.11083+00
3 BOTTM HOPPER ASH					.19599+01	.47018-01	.29399+01	.31644+00	.32490+00	.72988+00	.11128+00	.14272+01	.54485-03	.16137+00
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 105 - VERTICAL + STOKER BOILER						
1				1	.27250-01	.23476-02	.76791-03	.93904-01	.28215-01	.58800-01	.98731-02	.14261+00	.84689-03	.78107-02
1				3	.90832-01	.46952-02	.15665-02	.15051+00	.16938+00	.82495-01	.42257-02	.28654+00	.46952-04	.12550-01
2				1	.19940-01	.15863-02	.10502+00	.13072-01	.33765-02	.36778-01	.18167-01	.49185-01	.70011-03	.73556-02
2				3	.66466-01	.31682-02	.21003+00	.20915-01	.20250-01	.51400-01	.77987-02	.98370-01	.38772-04	.11742-01
3				1	.19940-01	.15863-02	.10502+00	.13072-01	.33765-02	.36778-01	.18167-01	.49185-01	.70011-03	.73556-02
3				3	.66466-01	.31682-02	.21003+00	.20915-01	.20250-01	.51400-01	.77987-02	.98370-01	.38772-04	.11742-01
5				1	.19514-01	.16176-03	.44052-02	.75371-03	.27670-03	.16176-02	.90170-03	.33384-02	.27120-04	.18240-03
5				3	.65046-01	.32351-03	.88105-02	.12046-02	.16589-02	.22646-02	.19342-03	.66767-02	.15074-05	.29185-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.86643-01	.56820-02	.21521+00	.12080+00	.35245-01	.13397+00	.47109-01	.24432+00	.22742-02	.22704-01
3 BOTTM HOPPER ASH					.28881+00	.11355-01	.43044+00	.19354+00	.21154+00	.18756+00	.20016-01	.48995+00	.12600-03	.36326-01
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 106 - FRONT WALL FIRING, WET						
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 107 - HORIZONTALLY OPPOSED,WET						
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
SECTOR 1 TOTAL					.13085+02	.49222+00	.32894+02	.52373+01	.42471+01	.10182+02	.34107+01	.16827+02	.82587-01	.25010+01
BY FUEL --														
1 ANTHRACITE					.11808+00	.70428-02	.23344-02	.24441+00	.19759+00	.14129+00	.14099-01	.42915+00	.89384-03	.20361-01
2 EASTERN BITUMIN.					.38849+01	.21377+00	.14165+02	.15281+01	.10623+01	.39646+01	.11675+01	.66342+01	.33221-01	.85866+00
3 CENTRAL BITUMIN.					.34671+01	.19078+00	.12642+02	.13637+01	.94804+00	.35383+01	.10419+01	.59208+01	.29648-01	.76633+00
4 WESTERN BITUMIN.					.12172+01	.66979-01	.44382+01	.47878+00	.33283+00	.12422+01	.36579+00	.20787+01	.10409-01	.26904+00
5 LIGNITE					.23783+01	.13648-01	.37169+00	.55076-01	.54438-01	.10918+00	.30800-01	.28167+00	.80514-03	.13338-01
6 HIGH S RES. OIL					.29960+00		.18919+00	.23255+00	.24512+00	.17599+00	.11732+00	.21998+00	.11292-02	.85060-01
7 MED S RES. OIL					.74991+00		.47355+00	.58210+00	.61356+00	.44051+00	.29367+00	.55063+00	.28266-02	.21291+00
8 LOW S RES. OIL					.96953+00		.61223+00	.75257+00	.79325+00	.56952+00	.37968+00	.71189+00	.36544-02	.27527+00
BY EFFLUENT STREAMS --														
1 FLUE GAS					.30195+01	.16422+00	.10600+02	.20186+01	.61088+00	.42459+01	.23876+01	.56086+01	.78243-01	.12366+01
3 BOTTM HOPPER ASH					.10065+02	.32800+00	.22294+02	.32187+01	.36362+01	.59356+01	.10231+01	.11218+02	.43440-02	.12644+01

Table B-7. (Continued)

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FUEL -CNTRL FAC- EFF                                         POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR     BA          BE          B           CH          CV          CU          PB          MN          HG          MO


            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  201 - PKG WALLFIRED WT 29-73MW
 14               1   .22456-01   .17865-02   .11827+00   .14721-01   .38026-02   .41420-01   .20460-01   .55393-01   .78847-05   .82839-02
 14               3   .74855-01   .35681-02   .23654+00   .23554-01   .22806-01   .57888-01   .87830-02   .11079+00   .43665-04   .13224-01
 15               1   .51392-01               .66965-02   .66965-01   .26475-01   .54506-01   .60736-01   .54506-01   .79424-03   .54506-01
 15               3   .17131+00               .13393+00   .10590+00   .15573+00   .76309-01   .26475-01   .10901+00   .45162-04   .87210-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .73848-01   .17865-02   .12497+00   .81686-01   .30277-01   .95926-01   .81196-01   .10990+00   .15827-02   .62790-01
  3 BOTTM HOPPER ASH  .24616+00   .35681-02   .37047+00   .12945+00   .17854+00   .13420+00   .35257-01   .21980+00   .88828-04   .21945-01

            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  202 - PKG STOKER W-T   29-73MW
 14               1   .20521-01   .16325-02   .10807+00   .13452-01   .34748-02   .37849-01   .18696-01   .50617-01   .72050-03   .75698-02
 14               3   .68402-01   .32605-02   .21615+00   .21524-01   .20840-01   .52897-01   .80258-02   .10123+00   .39901-04   .12084-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .20521-01   .16325-02   .10807+00   .13452-01   .34748-02   .37849-01   .18696-01   .50617-01   .72050-03   .75698-02
  3 BOTTM HOPPER ASH  .68402-01   .32605-02   .21615+00   .21524-01   .20840-01   .52897-01   .80258-02   .10123+00   .39901-04   .12084-01

            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29MW
 15               1   .48126-01               .62710-02   .62710-01   .24792-01   .51043-01   .56877-01   .51043-01   .74377-03   .51043-01
 15               3   .16042+00               .12542+00   .99170-01   .14584+00   .71461-01   .24792-01   .10209+00   .42293-04   .81669-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .48126-01               .62710-02   .62710-01   .24792-01   .51043-01   .56877-01   .51043-01   .74377-03   .51043-01
  3 BOTTM HOPPER ASH  .16042+00               .12542+00   .99170-01   .14584+00   .71461-01   .24792-01   .10209+00   .42293-04   .81669-02

            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29MW
 15               1   .24702-01               .32188-02   .32188-01   .12725-01   .26199-01   .29193-01   .26199-01   .38176-03   .26199-01
 15               3   .82340-01               .64375-01   .50901-01   .74855-01   .36679-01   .12725-01   .52398-01   .21708-04   .41919-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .24702-01               .32188-02   .32188-01   .12725-01   .26199-01   .29193-01   .26199-01   .38176-03   .26199-01
  3 BOTTM HOPPER ASH  .82340-01               .64375-01   .50901-01   .74855-01   .36679-01   .12725-01   .52398-01   .21708-04   .41919-02

            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29MW
 15               1   .15900-01               .20718-02   .20718-01   .81910-02   .16864-01   .18791-01   .16864-01   .24573-03   .16864-01
 15               3   .53001-01               .41437-01   .32764-01   .48182-01   .23609-01   .81910-02   .33728-01   .13973-04   .26982-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .15900-01               .20718-02   .20718-01   .81910-02   .16864-01   .18791-01   .16864-01   .24573-03   .16864-01
  3 BOTTM HOPPER ASH  .53001-01               .41437-01   .32764-01   .48182-01   .23609-01   .81910-02   .33728-01   .13973-04   .26982-02

            SECTOR     2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  206 - STOKER WATER TUBE  <29MW
  1               1   .13358-02   .11508-03   .37642-04   .46031-02   .13831-02   .28823-02   .48397-03   .69907-02   .41514-04   .38288-03
  1               3   .44526-02   .23016-03   .76791-04   .73779-02   .83029-02   .40439-02   .20714-03   .14046-01   .23016-05   .61519-03
 14               1   .67563-01   .53750-02   .35583+00   .44291-01   .11441-01   .12462+00   .61557-01   .16666+00   .23722-02   .24923-01
 14               3   .22521+00   .10735-01   .71166+00   .70866-01   .68614-01   .17416+00   .26425-01   .33351+00   .13137-03   .39787-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .68899-01   .54901-02   .35587+00   .48894-01   .12824-01   .12750+00   .62041-01   .17365+00   .24137-02   .25306-01
  3 BOTTM HOPPER ASH  .22966+00   .10965-01   .71174+00   .78244-01   .76917-01   .17621+00   .26632-01   .34736+00   .13367-03   .40402-01
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Table B-7. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR      BA         BE          B          CR         CO         CU         PB         MN         HG         MO


          SECTOR    2 - INDUSTRIAL BOILERS                    EQUIPMENT TYPE  208 - CAST IRON BOILERS
 15               1   .66724-01             .86943-02  .86943-01  .34373-01  .70768-01  .78856-01  .70768-01  .10312-02  .70768-01
 15               3   .22241+00             .17389+00  .13749+00  .20219+00  .99075-01  .34373-01  .14154+00  .58636-04  .11323-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .66724-01             .86943-02  .86943-01  .34373-01  .70768-01  .78856-01  .70768-01  .10312-02  .70768-01
  3 BOTTM HOPPER ASH  .22241+00             .17389+00  .13749+00  .20219+00  .99075-01  .34373-01  .14154+00  .58636-04  .11323-01

          SECTOR    2 - INDUSTRIAL BOILERS                    EQUIPMENT TYPE  209 - STOKER FIRETUBE      <29MW
  1               1   .21372-02  .18413-03  .60228-04  .73650-02  .22129-02  .46117-02  .77436-03  .11185-01  .66423-04  .61260-03
  1               3   .71241-02  .36825-03  .12287-03  .11805-01  .13285-01  .64702-02  .33143-03  .22474-01  .36825-05  .98430-03
 14               1   .19746-01  .15709-02  .10400+00  .12945-01  .33437-02  .36421-01  .17991-01  .48707-01  .69331-03  .72841-02
 14               3   .65821-01  .31374-02  .20799+00  .20712-01  .20053-01  .50901-01  .77230-02  .97414-01  .38395-04  .11628-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .21883-01  .17550-02  .10406+00  .20310-01  .55566-02  .41032-01  .18765-01  .59892-01  .75973-03  .78968-02
  3 BOTTM HOPPER ASH  .72945-01  .35057-02  .20812+00  .32516-01  .33338-01  .57371-01  .80544-02  .11989+00  .42078-04  .12613-01

          SECTOR    2 - INDUSTRIAL BOILERS                    EQUIPMENT TYPE  210 - HRT BOILER           <29MW
 15               1   .96537-02             .12579-02  .12579-01  .49731-02  .10239-01  .11409-01  .10239-01  .14919-03  .10239-01
 15               3   .32179-01             .25158-01  .19892-01  .29254-01  .14334-01  .49731-02  .20478-01  .84835-05  .16382-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .96537-02             .12579-02  .12579-01  .49731-02  .10239-01  .11409-01  .10239-01  .14919-03  .10239-01
  3 BOTTM HOPPER ASH  .32179-01             .25158-01  .19892-01  .29254-01  .14334-01  .49731-02  .20478-01  .84835-05  .16382-02

          SECTOR    2 - INDUSTRIAL BOILERS                    EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
  1               1   .64384-02  .55468-03  .18144-03  .22187-01  .66665-02  .13893-01  .23328-02  .33695-01  .20010-03  .18455-02
  1               3   .21461-01  .11094-02  .37013-03  .35562-01  .40020-01  .19492-01  .99842-03  .67702-01  .11094-04  .29652-02
 14               1   .36589-02  .29108-03  .19270-01  .23986-02  .61957-03  .67485-02  .33336-02  .90252-02  .12847-03  .13497-02
 14               3   .12196-01  .58135-03  .38540-01  .38377-02  .37158-02  .94317-02  .14310-02  .18050-01  .71144-05  .21547-02
 15               1   .15545-01             .20256-02  .20256-01  .80082-02  .16487-01  .18372-01  .16487-01  .24025-03  .16487-01
 15               3   .51818-01             .40512-01  .32033-01  .47107-01  .23082-01  .80082-02  .32975-01  .13661-04  .26380-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .25643-01  .84576-03  .21477-01  .44842-01  .15294-01  .37129-01  .24038-01  .59208-01  .56881-03  .19683-01
  3 BOTTM HOPPER ASH  .85475-01  .16907-02  .79422-01  .71432-01  .90842-01  .52006-01  .10438-01  .11873+00  .31869-04  .77578-02

          SECTOR    2 - INDUSTRIAL BOILERS                    EQUIPMENT TYPE  221 - TANGENTIAL BOILERS >73MW
  2               1   .14326-01  .11397-02  .75448-01  .93913-02  .24258-02  .26423-01  .13052-01  .35337-01  .50299-03  .52846-02
  2               3   .47752-01  .22762-02  .15090+00  .15026-01  .14549-01  .36928-01  .56029-02  .70673-01  .27855-04  .84362-02
  3               1   .87115-02  .69305-03  .45881-01  .57109-02  .14752-02  .16068-01  .79372-02  .21488-01  .30587-03  .32136-02
  3               3   .29038-01  .13842-02  .91762-01  .91374-02  .88471-02  .22456-01  .34072-02  .42977-01  .16939-04  .51301-02
  4               1   .48397-02  .38503-03  .25489-01  .31727-02  .81953-03  .89266-02  .44095-02  .11938-01  .16993-03  .17853-02
  4               3   .16132-01  .76898-03  .50979-01  .50764-02  .49150-02  .12476-01  .18929-02  .23876-01  .94106-05  .28501-02
  5               1   .24392-02  .20219-04  .55066-03  .94214-04  .34588-04  .20219-03  .11271-03  .41729-03  .33900-05  .22801-04
  5               3   .81308-02  .40439-04  .11013-02  .15057-03  .20736-03  .28307-03  .24177-04  .83459-03  .18843-06  .36481-04
  6               1   .28393-02             .36997-03  .36997-02  .14627-02  .30114-02  .33556-02  .30114-02  .43880-04  .30114-02
  6               3   .94644-02             .73994-02  .58507-02  .86040-02  .42160-02  .14627-02  .60228-02  .24952-05  .48182-03
  7               1   .72403-02             .94343-03  .94343-02  .37298-02  .76791-02  .85567-02  .76791-02  .11190-03  .76791-02
  7               3   .24134-01             .18869-01  .14919-01  .21940-01  .10751-01  .37298-02  .15358-01  .63627-05  .12287-02
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Table B-7. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR     BA         BE          B          CR         CO         CU         PB         MN         HG         MO

  8              1   .92278-02             .12024-02  .12024-01  .47537-02  .97870-02  .10906-01  .97870-02  .14261-03  .97870-02
  8              3   .30759-01             .24048-01  .19015-01  .27963-01  .13702-01  .47537-02  .19574-01  .81093-05  .15659-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS          .49624-01  .22380-02  .14989+00  .43527-01  .14701-01  .72097-01  .48330-01  .89658-01  .12806-02  .30784-01
 3 BOTTM HOPPER ASH  .16541+00  .44698-02  .34505+00  .69475-01  .87025-01  .10081+00  .20873-01  .17932+00  .71361-04  .19729-01

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  222 - WALL FIRED - DRY   >73MW
  2              1   .58077-02  .46203-03  .30587-01  .38073-02  .98344-03  .10712-01  .52915-02  .14326-01  .20391-03  .21424-02
  2              3   .19359-01  .92278-03  .61174-01  .60916-02  .58980-02  .14971-01  .22715-02  .28651-01  .11293-04  .34201-02
  3              1   .32910-02  .26182-03  .17333-01  .21575-02  .55728-03  .60701-02  .29985-02  .81179-02  .11555-03  .12140-02
  3              3   .10970-01  .52291-03  .34666-01  .34519-02  .33442-02  .84835-02  .12872-02  .16236-01  .63992-05  .19381-02
  4              1   .19359-02  .15401-03  .10196-01  .12691-02  .32781-03  .35707-02  .17638-02  .47752-02  .67972-04  .71413-03
  4              3   .64530-02  .30759-03  .20391-01  .20305-02  .19660-02  .49903-02  .75715-03  .95504-02  .37642-05  .11400-02
  5              1   .12196-02  .10110-04  .27533-03  .47107-04  .17294-04  .10110-03  .56356-04  .20865-03  .16950-05  .11400-04
  5              3   .40654-02  .20219-04  .55066-03  .75285-04  .10368-03  .14154-03  .12089-04  .41729-03  .94214-07  .18240-04
  6              1   .28393-02             .36997-03  .36997-02  .14627-02  .30114-02  .33556-02  .30114-02  .43880-04  .30114-02
  6              3   .94644-02             .73994-02  .58507-02  .86040-02  .42160-02  .14627-02  .60228-02  .24952-05  .48182-03
  7              1   .72403-02             .94343-03  .94343-02  .37298-02  .76791-02  .85567-02  .76791-02  .11190-03  .76791-02
  7              3   .24134-01             .18869-01  .14919-01  .21940-01  .10751-01  .37298-02  .15358-01  .63627-05  .12287-02
  8              1   .92278-02             .12024-02  .12024-01  .47537-02  .97870-02  .10906-01  .97870-02  .14261-03  .97870-02
  8              3   .30759-01             .24048-01  .19015-01  .27963-01  .13702-01  .47537-02  .19574-01  .81093-05  .15659-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS          .31562-01  .88798-03  .60907-01  .32439-01  .11832-01  .40931-01  .32928-01  .47905-01  .68752-03  .24559-01
 3 BOTTM HOPPER ASH  .10521+00  .17735-02  .16710+00  .51434-01  .69817-01  .57255-01  .14274-01  .95810-01  .38518-04  .97928-02

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  223 - OPPOSED WALL - DRY >73MW
  2              1   .17423-02  .13861-03  .91762-02  .11422-02  .29503-03  .32136-02  .15874-02  .42977-02  .61174-04  .64272-03
  2              3   .58077-02  .27683-03  .18352-01  .18275-02  .17694-02  .44913-02  .68144-03  .85954-02  .33878-05  .10260-02
  3              1   .11615-02  .92407-04  .61174-02  .76145-03  .19669-03  .21424-02  .10583-02  .28651-02  .40783-04  .42848-03
  3              3   .38718-02  .18456-03  .12235-01  .12183-02  .11796-02  .29942-02  .45429-03  .57303-02  .22585-05  .68402-03
  4              1   .58077-03  .46203-04  .30587-02  .38073-03  .98344-04  .10712-02  .52915-03  .14326-02  .20391-04  .21424-03
  4              3   .19359-02  .92278-04  .61174-02  .60916-03  .58980-03  .14971-02  .22715-03  .28651-02  .11293-05  .34201-03
  5              1   .97569-03  .80878-05  .22026-03  .37686-04  .13835-04  .80878-04  .45085-04  .16692-03  .13560-05  .91202-05
  5              3   .32523-02  .16176-04  .44052-03  .60228-04  .82943-04  .11323-03  .96709-05  .33384-03  .75371-07  .14592-04
  6              1   .11357-02             .14799-03  .14799-02  .58507-03  .12046-02  .13422-02  .12046-02  .17552-04  .12046-02
  6              3   .37858-02             .29598-02  .23403-02  .34416-02  .16864-02  .58507-03  .24091-02  .99806-06  .19273-03
  7              1   .28393-02             .36997-03  .36997-02  .14627-02  .30114-02  .33556-02  .30114-02  .43880-04  .30114-02
  7              3   .94644-02             .73994-02  .58507-02  .86040-02  .42160-02  .14627-02  .60228-02  .24952-05  .48182-03
  8              1   .38331-02             .49946-03  .49946-02  .19746-02  .40654-02  .45300-02  .40654-02  .59239-04  .40654-02
  8              3   .12777-01             .99892-02  .78985-02  .11615-01  .56915-02  .19746-02  .81308-02  .33685-05  .65046-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
 1 FLUE GAS          .12268-01  .28531-03  .19590-01  .12496-01  .46263-02  .14789-01  .12448-01  .17044-01  .24438-03  .95759-02
 3 BOTTM HOPPER ASH  .40895-01  .56984-03  .57494-01  .19805-01  .27283-01  .20690-01  .53949-02  .34087-01  .13713-04  .33917-02

         SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  224 - CYCLONE  BOILERS   >73MW
  2              1   .96795-03  .77006-04  .50979-02  .63455-03  .16391-03  .17853-02  .88191-03  .23876-02  .33986-04  .35707-03
  2              3   .32265-02  .15380-03  .10196-01  .10153-02  .98301-03  .24952-02  .37858-03  .47752-02  .18821-05  .57001-03
  3              1   .71628-02  .56984-03  .37724-01  .46956-02  .12129-02  .13211-01  .65261-02  .17668-01  .25149-03  .26423-02
  3              3   .23876-01  .11381-02  .75448-01  .75130-02  .72743-02  .18464-01  .28015-02  .35337-01  .13928-04  .42181-02
  5              1   .73177-02  .60658-04  .16520-02  .28264-03  .10376-03  .60658-03  .33814-03  .12519-02  .10170-04  .68402-04
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Table B-7. (Continued)

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FUEL -CNTRL FAC- EFF                                           POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR      BA          BE          B           CR          CO          CU          PB          MN          HG          MO

  5               3   .24392-01  .12132-03  .33039-02  .45171-03  .62207-03  .84921-03  .72532-04  .25038-02  .56528-06  .10944-03
  6               1   .14197-03             .18499-04  .18499-03  .73134-04  .15057-03  .16778-03  .15057-03  .21940-05  .15057-03
  6               3   .47322-03             .36997-03  .29254-03  .43020-03  .21080-03  .73134-04  .30114-03  .12476-06  .24091-04
  7               1   .42590-03             .55496-04  .55496-03  .21940-03  .45171-03  .50333-03  .45171-03  .65821-05  .45171-03
  7               3   .14197-02             .11099-02  .87761-03  .12906-02  .63239-03  .21940-03  .90342-03  .37427-06  .72274-04
  8               1   .56786-03             .73994-04  .73994-03  .29254-03  .60228-03  .67111-03  .60228-03  .87761-05  .60228-03
  8               3   .18929-02             .14799-02  .11701-02  .17208-02  .84319-03  .29254-03  .12046-02  .49903-06  .96365-04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .16584-01  .70751-03  .44622-01  .70927-02  .20656-02  .16808-01  .90884-02  .22512-01  .31320-03  .42723-02
  3 BOTTM HOPPER ASH  .55281-01  .14132-02  .91908-01  .11320-01  .12321-01  .23495-01  .38376-02  .45025-01  .17373-04  .50903-02

          SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  225 - VERTICAL/STOKER     >73MW
  1               1   .80146-03  .69047-04  .22585-04  .27619-02  .82986-03  .17294-02  .29038-03  .41944-02  .24909-04  .22973-03
  1               3   .26715-02  .13809-03  .46074-04  .44268-02  .49817-02  .24263-02  .12428-03  .84276-02  .13809-05  .36911-03
  2               1   .58077-03  .46203-04  .30587-02  .38073-03  .98344-04  .10712-02  .52915-03  .14326-02  .20391-04  .21424-03
  2               3   .19359-02  .92278-04  .61174-02  .60916-03  .58980-03  .14971-02  .22715-03  .28651-02  .11293-05  .34201-03
  3               1   .58077-03  .46203-04  .30587-02  .38073-03  .98344-04  .10712-02  .52915-03  .14326-02  .20391-04  .21424-03
  3               3   .19359-02  .92278-04  .61174-02  .60916-03  .58980-03  .14971-02  .22715-03  .28651-02  .11293-05  .34201-03
  5               1   .48785-03  .40439-05  .11013-03  .18843-04  .69176-05  .40439-04  .22542-04  .83459-04  .67800-06  .45601-05
  5               3   .16262-02  .80878-05  .22026-03  .30114-04  .41471-04  .56614-04  .48354-05  .16692-03  .37686-07  .72962-05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .24508-02  .16550-03  .62502-02  .35422-02  .10335-02  .39122-02  .13712-02  .71430-02  .66370-04  .66277-03
  3 BOTTM HOPPER ASH  .81695-02  .33074-03  .12501-01  .56752-02  .62028-02  .54771-02  .58341-03  .14325-01  .36772-05  .10604-02

          SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  226 - WALL FIRED - WET   >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

          SECTOR    2 - INDUSTRIAL BOILERS             EQUIPMENT TYPE  227 - OPPOSED WALL - WET >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

SECTOR    2 TOTAL
                      .21163+01  .47341-01  .37074+01  .13542+01  .12902+01  .15906+01  .72245+00  .24384+01  .11815-01  .53010+00

   BY FUEL --
  1 ANTHRACITE        .46422-01  .27688-02  .91775-03  .96088-01  .77681-01  .55548-01  .55428-02  .16871+00  .35140-03  .80045-02
  2 EASTERN BITUMIN.  .10151+00  .55854-02  .37011+00  .39926-01  .27755-01  .10359+00  .30504-01  .17334+00  .86800-03  .22435-01
  3 CENTRAL BITUMIN.  .90600-01  .49853-02  .33034+00  .35636-01  .24773-01  .92459-01  .27226-01  .15472+00  .77475-03  .20025-01
  4 WESTERN BITUMIN.  .31878-01  .17541-02  .11623+00  .12539-01  .87165-02  .32532-01  .95797-02  .54468-01  .27260-03  .70458-02
  5 LIGNITE           .53907-01  .30936-03  .84250-02  .12484-02  .12339-02  .24749-02  .69814-03  .63846-02  .18250-04  .30234-03
  6 HIGH S RES. OIL   .30144-01             .19035-01  .23399-01  .24663-01  .17707-01  .11805-01  .22134-01  .11362-03  .85584-02
  7 MED  S RES. OIL   .76898-01             .48559-01  .59690-01  .62947-01  .45171-01  .30114-01  .56464-01  .28985-03  .21833-01
  8 LOW  S RES. OIL   .99045-01             .62544-01  .76881-01  .81037-01  .58180-01  .38787-01  .72725-01  .37332-03  .28120-01
 14 BIT/LIG COAL      .58043+00  .31938-01  .21163+01  .22830+00  .15871+00  .59233+00  .17443+00  .99119+00  .49634-02  .12829+00
 15 RESIDUAL OIL      .10055+01             .63496+00  .78051+00  .82270+00  .59066+00  .39377+00  .73832+00  .37900-02  .28548+00

   BY EFFLUENT STREAMS --
  1 FLUE GAS          .48839+00  .15794-01  .10172+01  .52342+00  .18674+00  .66309+00  .50403+00  .81264+00  .11189-01  .36821+00
  3 BOTTM HOPPER ASH  .16280+01  .31547-01  .26902+01  .83080+00  .11034+01  .92756+00  .21843+00  .16258+01  .62608-03  .16188+00

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Table B-7. (Concluded)

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FUEL -CNTRL FAC- EFF                                                    POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       BA          BE          B          CH          CO          CU          PB          MN          HG          MO

GRAND TOTAL
                       .15201+02  .53956+00  .36601+02  .65915+01  .55373+01  .11772+02  .41332+01  .19265+02  .94403-01  .30311+01

  BY FUEL --
 1 ANTHRACITE          .16450+00  .98116-02  .32522-02  .34050+00  .27527+00  .19684+00  .19642-01  .59787+00  .12452-02  .28365-01
 2 EASTERN BITUMIN.    .39864+01  .21935+00  .14535+02  .15680+01  .10900+01  .40682+01  .11980+01  .68076+01  .34089-01  .88110+00
 3 CENTRAL BITUMIN.    .35577+01  .19577+00  .12972+02  .13994+01  .97281+00  .36307+01  .10691+01  .60755+01  .30423-01  .78635+00
 4 WESTERN BITUMIN.    .12491+01  .68733-01  .45544+01  .49132+00  .34155+00  .12747+01  .37537+00  .21331+01  .10681-01  .27608+00
 5 LIGNITE             .24322+01  .13957-01  .38012+00  .56325-01  .55671-01  .11166+00  .31498-01  .28806+00  .82339-03  .13641-01
 6 HIGH S RES. OIL     .32974+00             .20822+00  .25595+00  .26979+00  .19369+00  .12913+00  .24212+00  .12429-02  .93618-01
 7 MED  S RES. OIL     .82681+00             .52210+00  .64179+00  .67648+00  .48568+00  .32379+00  .60710+00  .31164-02  .23474+00
 8 LOW  S RES. OIL     .10686+01             .67477+00  .82946+00  .87429+00  .62770+00  .41846+00  .78462+00  .40277-02  .30359+00
14 BIT/LIG COAL        .58043+00  .31938-01  .21163+01  .22830+00  .15871+00  .59233+00  .17443+00  .99119+00  .49634-02  .12829+00
15 RESIDUAL OIL        .10055+01             .63496+00  .78051+00  .82270+00  .59066+00  .39377+00  .73852+00  .37900-02  .28548+00
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Table B-8. Trace Specie Emissions by Equipment Type and Fuel -- 1977

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FUEL -CNTRL FAC- EFF                                              POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3   STR        NI          V           ZN          ZR          AS          BI          AL          SB          CD          SE


          SECTOR    1 - UTILITY BOILERS                           EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
  2      .01          1    .57212+00  .10187+01  .79974+01  .73945+00  .38142+00  .25592-01  .25100+03  .34450-01  .10384+00  .14272+00
  2      .01          3    .68655+00  .10187+01  .79974+01  .44416+01  .38142+00  .35927-01  .62749+03  .41340-01  .59304-01  .30636-01
  3      .01          1    .36568+00  .65114+00  .51116+01  .47263+00  .24379+00  .16357-01  .16043+03  .22019-01  .66373-01  .91223-01
  3      .01          3    .43881+00  .65114+00  .51116+01  .28389+01  .24379+00  .22963-01  .40107+03  .26423-01  .37905-01  .19581-01
  4      .01          1    .18964+00  .33768+00  .26509+01  .24511+00  .12643+00  .84829-02  .83197+02  .11419-01  .34421-01  .47308-01
  4      .01          3    .22757+00  .33768+00  .26509+01  .14723+01  .12643+00  .11909-01  .20799+03  .13703-01  .19657-01  .10155-01
  5                   1    .67756-02  .18068-01  .55410-01  .30114-01  .75285-02  .15057-02  .56012+01  .37642-03  .26350-03  .34029-02
  5                   3    .81308-02  .18068-01  .55410-01  .18068+00  .75285-02  .21080-02  .14003+02  .45171-03  .15057-03  .73177+02
  6                   1    .17036+01  .25554+01  .46849-01  .93698-02  .23850-03             .73254+00  .23850-03  .33220-03  .34072-01
  6                   3    .17036+01  .25554+01  .46849-01  .56219-01  .23850-03             .17036+01  .28109-03  .18740-02  .73254-02
  7                   1    .42676+01  .64014+01  .11736+00  .23472-01  .59746-03             .18351+01  .59746-03  .83218-03  .85352-01
  7                   3    .42676+01  .64014+01  .11736+00  .14083+00  .59746-03             .42676+01  .70415-03  .46943-02  .18351-01
  8                   1    .55152+01  .82727+01  .15167+00  .30333-01  .77212-03             .23715+01  .77212-03  .10755-02  .11030+00
  8                   3    .55152+01  .82727+01  .15167+00  .18200+00  .77212-03             .55152+01  .91000-03  .60667-02  .23715-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS               .12621+02  .19255+02  .16131+02  .15505+01  .76076+00  .51938-01  .50516+03  .69874-01  .20714+00  .51438+00
  3 BOTTM HOPPER ASH       .12847+02  .19255+02  .16131+02  .93126+01  .76076+00  .72907-01  .12620+04  .83814-01  .12965+00  .73287+02

          SECTOR    1 - UTILITY BOILERS                           EQUIPMENT TYPE  102 - WALL FIRED BOILER
  2  .01 .01          1    .21185+00  .37722+00  .29613+01  .27380+00  .14123+00  .94761-02  .92939+02  .12756-01  .38451-01  .52847-01
  2  .01 .01          3    .25421+00  .37722+00  .29613+01  .16447+01  .14123+00  .13303-01  .23235+03  .15308-01  .21959-01  .11344-01
  3  .01 .01          1    .12883+00  .22940+00  .18008+01  .16651+00  .85885-01  .57626-02  .56518+02  .77574-02  .23383-01  .32158-01
  3  .01 .01          3    .15459+00  .22940+00  .18008+01  .10001+01  .85885-01  .80898-02  .14129+03  .93088-02  .13354-01  .68985-02
  4  .01 .01          1    .70215-01  .12503+00  .98150+00  .90751-01  .46810-01  .31408-02  .30804+02  .42280-02  .12744-01  .17516-01
  4  .01 .01          3    .84258-01  .12503+00  .98150+00  .54511+00  .46810-01  .44092-02  .77010+02  .50736-02  .72782-02  .37599-02
  5                   1    .58077-03  .15487-02  .47494-02  .25812-02  .64530-03  .12906-03  .48010+00  .32265-04  .22585-04  .29168-03
  5                   3    .69692-03  .15487-02  .47494-02  .15487-01  .64530-03  .18068-03  .12003+01  .38718-04  .12906-04  .62723+01
  6  .09              1    .17036+01  .25554+01  .46849-01  .93698-02  .23850-03             .73254+00  .23850-03  .33220-03  .34072-01
  6  .09              3    .17036+01  .25554+01  .46849-01  .56219-01  .23850-03             .17036+01  .28109-03  .18740-02  .73254-02
  7  .09              1    .42762+01  .64143+01  .11760+00  .23519-01  .59867-03             .18388+01  .59867-03  .83386-03  .85524-01
  7  .09              3    .42762+01  .64143+01  .11760+00  .14111+00  .59867-03             .42762+01  .70557-03  .47038-02  .18388-01
  8  .09              1    .55152+01  .82727+01  .15167+00  .30333-01  .77212-03             .23715+01  .77212-03  .10755-02  .11030+00
  8  .09              3    .55152+01  .82727+01  .15167+00  .18200+00  .77212-03             .55152+01  .91000-03  .60667-02  .23715-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS               .11906+02  .17976+02  .60645+01  .59687+00  .27618+00  .18509-01  .18568+03  .26383-01  .76843-01  .33269+00
  3 BOTTM HOPPER ASH       .11989+02  .17976+02  .60645+01  .35847+01  .27618+00  .25983-01  .46335+03  .31625-01  .55248-01  .63437+01

          SECTOR    1 - UTILITY BOILERS                           EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
  2  .20 .01          1    .92020-01  .16385+00  .12863+01  .11893+00  .61347-01  .41162-02  .40370+02  .55410-02  .16702-01  .22955-01
  2  .20 .01          3    .11042+00  .16385+00  .12863+01  .71439+00  .61347-01  .57784-02  .10092+03  .66492-02  .95384-02  .49275-02
  3  .20 .01          1    .69615-01  .12396+00  .97311+00  .89975-01  .46410-01  .31140-02  .30541+02  .41919-02  .12635-01  .17366-01
  3  .20 .01          3    .83538-01  .12396+00  .97311+00  .54045+00  .46410-01  .43715-02  .76352+02  .50302-02  .72160-02  .37278-02
  4  .20 .01          1    .30407-01  .54143-01  .42504+00  .39300-01  .20271-01  .13601-02  .13340+02  .18309-02  .55189-02  .75853-02
  4  .20 .01          3    .36488-01  .54143-01  .42504+00  .23606+00  .20271-01  .19094-02  .33349+02  .21971-02  .31518-02  .16282-02
  5                   1    .11615-02  .30974-02  .94988-02  .51624-02  .12906-02  .25812-03  .96021+00  .64530-04  .45171-04  .58335-03
  5                   3    .13938-02  .30974-02  .94988-02  .30974-01  .12906-02  .36137-03  .24005+01  .77436-04  .25812-04  .12545+02
  6  .26              1    .68832+00  .10325+01  .18929-01  .37858-02  .96365-04             .29598+00  .96365-04  .13422-03  .13766-01
  6  .26              3    .68832+00  .10325+01  .18929-01  .22715-01  .96365-04             .68832+00  .11357-03  .75715-03  .29598-02
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Table B-8. (Continued)

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FUEL -CNTRL FAC- EFF                                  POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI         V          ZN         ZR         AS         BI         AL         SB         CD         SE

  7  .26           1  .17208+01  .25812+01  .47322-01  .94644-02  .24091-03             .73994+00  .24091-03  .33556-03  .34416-01
  7  .26           3  .17208+01  .25812+01  .47322-01  .56786-01  .24091-03             .17208+01  .28393-03  .18929-02  .73994-02
  8  .26           1  .22284+01  .33427+01  .61282-01  .12256-01  .31198-03             .95823+00  .31198-03  .43455-03  .44569-01
  8  .26           3  .22284+01  .33427+01  .61282-01  .73558-01  .31198-03             .22284+01  .36769-03  .24513-02  .95823-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .48308+01  .73014+01  .28215+01  .27888+00  .12997+00  .88484-02  .87205+02  .12278-01  .35806-01  .14124+00
  3 BOTTM HOPPER ASH  .48694+01  .73014+01  .28215+01  .16749+01  .12997+00  .12421-01  .21766+03  .14719-01  .25033-01  .12575+02

           SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  104 - CYCLONE BOILER
  2                1  .29806-01  .53075-01  .41665+00  .38524-01  .19871-01  .13333-02  .13076+02  .17948-02  .54100-02  .74356-02
  2                3  .35768-01  .53075-01  .41665+00  .23140+00  .19871-01  .18717-02  .32691+02  .21588-02  .30896-02  .15961-02
  3                1  .24205+00  .43101+00  .33835+01  .31285+00  .16137+00  .10827-01  .10619+03  .14575-01  .43934-01  .60383-01
  3                3  .29046+00  .43101+00  .33835+01  .18792+01  .16137+00  .15200-01  .26548+03  .17490-01  .25090-01  .12961-01
  5                1  .12487-01  .33297-01  .10211+00  .55496-01  .13874-01  .27748-02  .10322+02  .69370-03  .48559-03  .62710-02
  5                3  .14984-01  .33297-01  .10211+00  .33297+00  .13874-01  .38847-02  .25806+02  .83244-03  .27748-03  .13485+03
  6                1  .94644-01  .14197+00  .26027-02  .52054-03  .13250-04             .40697-01  .13250-04  .18456-04  .18929-02
  6                3  .94644-01  .14197+00  .26027-02  .31233-02  .13250-04             .94644-01  .15616-04  .10411-03  .40697-03
  7                1  .22370+00  .33556+00  .61519-02  .12304-02  .31319-04             .96193-01  .31319-04  .43622-04  .44741-02
  7                3  .22370+00  .33556+00  .61519-02  .73822-02  .31319-04             .22370+00  .36911-04  .24607-03  .96193-03
  8                1  .30114+00  .45171+00  .82813-02  .16563-02  .42160-04             .12949+00  .42160-04  .58722-04  .60228-02
  8                3  .30114+00  .45171+00  .82813-02  .99376-02  .42160-04             .30114+00  .49608-04  .33125-03  .12949-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .90383+00  .14466+01  .39193+01  .41027+00  .19520+00  .14935-01  .12986+03  .17150-01  .49950-01  .86479-01
  3 BOTTM HOPPER ASH  .96070+00  .14466+01  .39193+01  .24640+01  .19520+00  .20956-01  .32459+03  .20579-01  .29139-01  .13487+03

           SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
  1                1  .39141-01  .12243-01  .25889-01  .15051-01  .78107-02  .78107-04             .78107-04  .10970-03  .43880-03
  1                3  .46952-01  .12243-01  .25889-01  .90394-01  .78107-02  .10970-03             .93904-04  .62749-04  .93904-04
  2                1  .20604-01  .36689-01  .28802+00  .26631-01  .13736-01  .92166-03  .90394+01  .12407-02  .37398-02  .51400-02
  2                3  .24725-01  .36689-01  .28802+00  .15996+00  .13736-01  .12939-02  .22598+02  .14888-02  .21358-02  .11033-02
  3                1  .20604-01  .36689-01  .28802+00  .26631-01  .13736-01  .92166-03  .90394+01  .12407-02  .37398-02  .51400-02
  3                3  .24725-01  .36689-01  .28802+00  .15996+00  .13736-01  .12939-02  .22598+02  .14888-02  .21358-02  .11033-02
  5                1  .77436-03  .20650-02  .63325-02  .34416-02  .86040-03  .17208-03  .64014+00  .43020-04  .30114-04  .38890-03
  5                3  .92923-03  .20650-02  .63325-02  .20650-01  .86040-03  .24091-03  .16003+01  .51624-04  .17208-04  .83631+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .81125-01  .87686-01  .60826+00  .71754-01  .36144-01  .20935-02  .18719+02  .26025-02  .76194-02  .11108-01
  3 BOTTM HOPPER ASH  .97332-01  .87686-01  .60826+00  .43097+00  .36144-01  .29384-02  .46797+02  .31232-02  .43515-02  .83654+01

           SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  106 - FRONT WALL FIRING, WET
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

           SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  107 - HORIZONTALLY OPPOSED,WET
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   BY FUEL --
  1 ANTHRACITE        .86093-01  .24485-01  .51779-01  .10544+00  .15621-01  .18781-03             .17201-03  .17245-03  .53271-03
  2 EASTERN BITUMIN.  .20381+01  .32992+01  .25899+02  .83894+01  .12352+01  .99613-01  .14225+04  .12272+00  .26417+00  .28071+00
  3 CENTRAL BITUMIN.  .18189+01  .29444+01  .23114+02  .74872+01  .11024+01  .88901-01  .12695+04  .10953+00  .23576+00  .25052+00
  4 WESTERN BITUMIN.  .63858+00  .10337+01  .81149+01  .26286+01  .38702+00  .31211-01  .44569+03  .38452-01  .82772-01  .87953-01
  5 LIGNITE           .47914-01  .11615+00  .35621+00  .67756+00  .48397-01  .11615-01  .63014+02  .26619-02  .13309-02  .23522+03
  6 HIGH S RES. OIL   .83803+01  .12570+02  .23046+00  .16132+00  .11732-02             .59919+01  .12780-02  .54262-02  .10182+00
  7 MED  S RES. OIL   .20977+02  .31465+02  .57686+00  .40380+00  .29367-02             .14998+02  .31989-02  .13582-01  .25487+00
  8 LOW  S RES. OIL   .27120+02  .40680+02  .74579+00  .52206+00  .37968-02             .19391+02  .41358-02  .17560-01  .32951+00

   BY EFFLUENT STREAMS --
  1 FLUE GAS          .30343+02  .46066+02  .29545+02  .29082+01  .13983+01  .96323-01  .92662+03  .12829+00  .37736+00  .10859+01
  3 BOTTM HOPPER ASH  .30764+02  .46066+02  .29545+02  .17467+02  .13983+01  .13520+00  .23144+04  .15386+00  .24342+00  .23544+03

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Table B-8. (Continued)

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FUEL -CNTRL FAC- EFF                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       NI         V          ZN         ZR         AS         BI         AL         SB         CD         SE

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  201 - PKG WALLFIRED WT 29-73MW
 14                  1  .23205-01  .41320-01  .32437+00  .29992-01  .15470-01  .10380-02  .10180+02  .13973-02  .42118-02  .57888-02
 14                  3  .27846-01  .41320-01  .32437+00  .18015+00  .15470-01  .14572-02  .25451+02  .16767-02  .24053-02  .12426-02
 15                  1  .31146+01  .46720+01  .85653-01  .17131-01  .43605-03             .13393+01  .43605-03  .60736-03  .62293-01
 15                  3  .31146+01  .46720+01  .85653-01  .10278+00  .43605-03             .31146+01  .51392-03  .34261-02  .13393-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .31379+01  .47133+01  .41002+00  .47122-01  .15906-01  .10380-02  .11520+02  .18333-02  .48192-02  .68082-01
  3 BOTTM HOPPER ASH    .31425+01  .47133+01  .41002+00  .28293+00  .15906-01  .14572-02  .28565+02  .21907-02  .58314-02  .14636-01

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  202 - PKG STOKER W-T   29-73MW
 14                  1  .21205-01  .37758-01  .29641+00  .27406-01  .14136-01  .94850-03  .93026+01  .12768-02  .38487-02  .52897-02
 14                  3  .25445-01  .37758-01  .29641+00  .16462+00  .14136-01  .13316-02  .23257+02  .15322-02  .21980-02  .11355-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .21205-01  .37758-01  .29641+00  .27406-01  .14136-01  .94850-03  .93026+01  .12768-02  .38487-02  .52897-02
  3 BOTTM HOPPER ASH    .25445-01  .37758-01  .29641+00  .16462+00  .14136-01  .13316-02  .23257+02  .15322-02  .21980-02  .11355-02

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29MW
 15                  1  .29168+01  .43751+01  .80211-01  .16042-01  .40835-03             .12542+01  .40835-03  .56877-03  .58335-01
 15                  3  .29168+01  .43751+01  .80211-01  .96253-01  .40835-03             .29168+01  .48126-03  .32084-02  .12542-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .29168+01  .43751+01  .80211-01  .16042-01  .40835-03             .12542+01  .40835-03  .56877-03  .58335-01
  3 BOTTM HOPPER ASH    .29168+01  .43751+01  .80211-01  .96253-01  .40835-03             .29168+01  .48126-03  .32084-02  .12542-01

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29MW
 15                  1  .14971+01  .22456+01  .41170-01  .82340-02  .20959-03             .64375+00  .20959-03  .29193-03  .29942-01
 15                  3  .14971+01  .22456+01  .41170-01  .49404-01  .20959-03             .14971+01  .24702-03  .16468-02  .64375-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .14971+01  .22456+01  .41170-01  .82340-02  .20959-03             .64375+00  .20959-03  .29193-03  .29942-01
  3 BOTTM HOPPER ASH    .14971+01  .22456+01  .41170-01  .49404-01  .20959-03             .14971+01  .24702-03  .16468-02  .64375-02

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29MW
 15                  1  .96365+00  .14455+01  .26500-01  .53001-02  .13491-03             .41437+00  .13491-03  .18791-03  .19273-01
 15                  3  .96365+00  .14455+01  .26500-01  .31800-01  .13491-03             .96365+00  .15900-03  .10600-02  .41437-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .96365+00  .14455+01  .26500-01  .53001-02  .13491-03             .41437+00  .13491-03  .18791-03  .19273-01
  3 BOTTM HOPPER ASH    .96365+00  .14455+01  .26500-01  .31800-01  .13491-03             .96365+00  .15900-03  .10600-02  .41437-02

          SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  206 - STOKER WATER TUBE  <29MW
  1                  1  .19187-02  .60013-03  .12691-02  .73779-03  .38288-03  .38288-05             .38288-05  .53775-05  .21510-04
  1                  3  .23016-02  .60013-03  .12691-02  .44311-02  .38288-03  .53775-05             .46031-05  .30759-05  .46031-05
 14                  1  .69815-01  .12432+00  .97591+00  .90234-01  .46543-01  .31229-02  .30629+02  .42039-02  .12672-01  .17416-01
 14                  3  .83778-01  .12432+00  .97591+00  .54200+00  .46543-01  .43841-02  .76571+02  .50447-02  .72367-02  .37385-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .71734-01  .12492+00  .97718+00  .90972-01  .46926-01  .31267-02  .30629+02  .42077-02  .12677-01  .17438-01
  3 BOTTM HOPPER ASH    .86080-01  .12492+00  .97718+00  .54644+00  .46926-01  .43895-02  .76571+02  .50493-02  .72398-02  .37431-02
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Table B-8. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI          V           ZN          ZR          A>          BI          AL          SB          CD          SE

          SECTOR    2 - INDUSTRIAL BOILERS                 EQUIPMENT TYPE  208 - CAST IRON BOILERS
 15                 1  .40439+01   .60658+01   .11121+00   .22241-01   .56614-03               .17389+01   .56614-03   .78856-03   .80878-01
 15                 3  .40439+01   .60658+01   .11121+00   .13345+00   .56614-03               .40439+01   .66724-u3   .44483-02   .17389-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .40439+01   .60658+01   .11121+00   .22241-01   .56614-03               .17389+01   .56614-03   .78856-03   .80878-01
  3 BOTTM HOPPER ASH   .40439+01   .60658+01   .11121+00   .13345+00   .56614-03               .40439+01   .66724-03   .44483-02   .17389-01

          SECTOR    2 - INDUSTRIAL BOILERS                 EQUIPMENT TYPE  209 - STOKER FIRETUBE           <29MW
  1                 1  .30699-02   .96021-03   .20305-02   .11805-02   .61260-03   .61260-05               .61260-u5   .86040-05   .34416-04
  1                 3  .36825-02   .96021-03   .20305-02   .70897-02   .61260-03   .86040-05               .73650-05   .49215-05   .73650-05
 14                 1  .20404-01   .36333-01   .28522+00   .26372-01   .13603-01   .91271-03   .89516+01   .12287-02   .37035-02   .50901-02
 14                 3  .24485-01   .36333-01   .28522+00   .15841+00   .13603-01   .12813-02   .22379+02   .14744-v2   .21150-02   .10926-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .23474-01   .37293-01   .28725+00   .27553-01   .14216-01   .91884-03   .89516+01   .12348-02   .37121-02   .51245-02
  3 BOTTM HOPPER ASH   .28168-01   .37293-01   .28725+00   .16550+00   .14216-01   .12899-02   .22379+02   .14817-02   .21200-02   .11000-02

          SECTOR    2 - INDUSTRIAL BOILERS                 EQUIPMENT TYPE  210 - HRT BOILER                <29MW
 15                 1  .58507+00   .87761+00   .16089-01   .32179-02   .81910-04               .25158+00   .81910-04   .11409-03   .11701-01
 15                 3  .58507+00   .87761+00   .16089-01   .19307-u1   .81910-04               .58507+00   .96537-u4   .64358-03   .25158-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .58507+00   .87761+00   .16089-01   .32179-02   .81910-04               .25158+00   .81910-04   .11409-03   .11701-01
  3 BOTTM HOPPER ASH   .58507+00   .87761+00   .16089-01   .19307-01   .81910-04               .58507+00   .96537-04   .64358-03   .25158-02

          SECTOR    2 - INDUSTRIAL BOILERS                 EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
  1                 1  .92481-02   .28926-02   .61170-02   .35562-02   .18455-02   .18455-04               .18455-04   .25920-04   .10368-03
  1                 3  .11094-01   .28926-02   .61170-02   .21958-01   .18455-02   .25920-04               .22187-04   .14826-04   .22187-04
 14                 1  .37808-02   .67323-02   .52850-01   .48866-02   .252u5-02   .16912-03   .16587+01   .22766-03   .68624-03   .94317-03
 14                 3  .45370-02   .67323-02   .52850-01   .29352-01   .25205-02   .23742-03   .41467+01   .27319-03   .39190-03   .20246-03
 15                 1  .94214+00   .14132+01   .25909-01   .51818-02   .13190-03               .40512+00   .13190-03   .18372-03   .18843-01
 15                 3  .94214+00   .14132+01   .25909-01   .31091-01   .13190-03               .94214+00   .15545-u3   .10364-02   .40512-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .95517+00   .14228+01   .84876-01   .13625-01   .44979-02   .18757-03   .20638+01   .37802-03   .89587-03   .19890-01
  3 BOTTM HOPPER ASH   .95777+00   .14228+01   .84876-01   .81800-01   .44979-02   .26334-03   .50888+01   .45083-03   .14431-02   .42758-02

          SECTOR    2 - INDUSTRIAL BOILERS                 EQUIPMENT TYPE  221 - TANGENTIAL BOILERS >73MW
  2                 1  .14803-01   .26359-01   .20693+00   .19133-01   .98688-02   .66216-03   .64943+01   .89137-03   .26869-02   .36928-02
  2                 3  .17764-01   .26359-01   .20693+00   .11492+00   .98688-02   .92958-03   .16236+02   .10696-02   .15344-02   .79269-03
  3                 1  .90019-02   .16029-01   .12583+00   .11635-01   .60013-02   .40267-03   .39492+01   .54205-u3   .16339-02   .22456-02
  3                 3  .10802-01   .16029-01   .12583+00   .69886-01   .60013-02   .56528-03   .98731+01   .65046-u3   .93310-03   .48204-03
  4                 1  .50011-02   .89051-02   .69907-01   .64638-02   .33340-02   .22370-03   .21940+01   .30114-03   .90772-03   .12476-02
  4                 3  .60013-02   .89051-02   .69907-01   .38826-01   .33340-02   .31405-03   .54850+01   .36137-03   .51839-03   .26780-03
  5                 1  .96795-04   .25812-03   .79157-03   .43020-03   .10755-03   .21510-04   .80017-01   .53775-05   .37642-05   .48613-04
  5                 3  .11615-03   .25812-03   .79157-03   .25812-02   .10755-03   .30114-04   .20004+00   .64530-05   .21510-05   .10454+01
  6                 1  .17208+00   .25812+00   .47322-02   .94644-03   .24091-04               .73994-01   .24091-04   .33556-04   .34416-02
  6                 3  .17208+00   .25812+00   .47322-02   .56786-02   .24091-04               .17208+00   .28393-04   .18929-03   .73994-03
  7                 1  .43880+00   .65821+00   .12067-01   .24134-02   .61433-04               .18869+00   .61433-04   .85567-04   .87761-02
  7                 3  .43880+00   .65821+00   .12067-01   .14481-01   .61433-04               .43880+00   .72403-04   .48268-03   .18869-02
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Table B-8. (Continued)

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FUEL -CNTRL FAC- EFF                                      POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR   NI         V          ZN         ZR         AS         BI         AL         SB         CD         SE

  8              1  .55926+00  .83889+00  .15380-01  .30759-02  .78296-04             .24048+00  .78296-04  .10906-03  .11185-01
  8              3  .55926+00  .83889+00  .15380-01  .18456-01  .78296-04             .55926+00  .92278-04  .61519-03  .24048-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .11990+01  .18068+01  .43564+00  .44097-01  .19475-01  .13100-02  .13221+02  .19038-02  .54604-02  .30638-01
  3 BOTTM HOPPER ASH .12048+01 .18068+01  .43564+00  .26483+00  .19475-01  .18390-02  .32964+02  .22810-02  .42752-02  .10520+01

         SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  222 - WALL FIRED - DRY   >73MW
  2              1  .60013-02  .10686-01  .83889-01  .77565-02  .40009-02  .26844-03  .26328+01  .36137-03  .10893-02  .14971-02
  2              3  .72015-02  .10686-01  .83889-01  .46591-01  .40009-02  .37686-03  .65821+01  .43364-03  .62207-03  .32136-03
  3              1  .34007-02  .60555-02  .47537-01  .43954-02  .22672-02  .15212-03  .14919+01  .20478-03  .61725-03  .84835-03
  3              3  .40809-02  .60555-02  .47537-01  .26401-01  .22672-02  .21355-03  .37298+01  .24573-03  .55251-03  .18210-03
  4              1  .20004-02  .35621-02  .27963-01  .25855-02  .13336-02  .89482-04  .87761+00  .12046-03  .36309-03  .49903-03
  4              3  .24005-02  .35621-02  .27963-01  .15530-01  .13336-02  .12562-03  .21940+01  .14455-03  .20736-03  .10712-03
  5              1  .48397-04  .12906-03  .39578-03  .21510-03  .53775-04  .10755-04  .40009-01  .26887-05  .18821-05  .24306-04
  5              3  .58077-04  .12906-03  .39578-03  .12906-02  .53775-04  .15057-04  .10002+00  .32265-05  .10755-05  .52269+00
  6              1  .17208+00  .25812+00  .47322-02  .94644-03  .24091-04             .73994-01  .24091-04  .33556-04  .34416-02
  6              3  .17208+00  .25812+00  .47322-02  .56786-02  .24091-04             .17208+00  .28393-04  .18929-03  .73994-03
  7              1  .43880+00  .65821+00  .12067-01  .24134-02  .61433-04             .18869+00  .61433-04  .85567-04  .87761-02
  7              3  .43880+00  .65821+00  .12067-01  .14481-01  .61433-04             .43880+00  .72403-04  .48268-03  .18869-02
  8              1  .55926+00  .83889+00  .15380-01  .30759-02  .78296-04             .24048+00  .78296-04  .10906-03  .11185-01
  8              3  .55926+00  .83889+00  .15380-01  .18456-01  .78296-04             .55926+00  .92278-04  .61519-03  .24048-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .11816+01  .17756+01  .19196+00  .21388-01  .78192-02  .52080-03  .55455+01  .85311-03  .22997-02  .26272-01
  3 BOTTM HOPPER ASH .11839+01 .17756+01  .19196+00  .12843+00  .78192-02  .73108-03  .13776+02  .10202-02  .24702-02  .52834+00

         SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  223 - OPPOSED WALL - DRY >73MW
  2              1  .18004-02  .32059-02  .25167-01  .23270-02  .12003-02  .80533-04  .78985+00  .10841-03  .32678-03  .44913-03
  2              3  .21605-02  .32059-02  .25167-01  .13977-01  .12003-02  .11306-03  .19746+01  .13009-03  .18662-03  .96408-04
  3              1  .12003-02  .21372-02  .16778-01  .15513-02  .80017-03  .53689-04  .52656+00  .72274-04  .21785-03  .29942-03
  3              3  .14403-02  .21372-02  .16778-01  .93181-02  .80017-03  .75371-04  .13164+01  .86728-04  .12441-03  .64272-04
  4              1  .60013-03  .10686-02  .83889-02  .77565-03  .40009-03  .26844-04  .26328+00  .36137-04  .10893-03  .14971-03
  4              3  .72015-03  .10686-02  .83889-02  .46591-02  .40009-03  .37686-04  .65821+00  .43364-04  .62207-04  .32136-04
  5              1  .38718-04  .10325-03  .31663-03  .17208-03  .43020-04  .86040-05  .32007-01  .21510-05  .15057-05  .19445-04
  5              3  .46462-04  .10325-03  .31663-03  .10325-02  .43020-04  .12046-04  .80017-01  .25812-05  .86040-06  .41815+00
  6              1  .68832-01  .10325+00  .18929-02  .37858-03  .96365-05             .29598-01  .96365-05  .13422-04  .13766-02
  6              3  .68832-01  .10325+00  .18929-02  .22715-02  .96365-05             .68832-01  .11357-04  .75715-04  .29598-03
  7              1  .17208+00  .25812+00  .47322-02  .94644-03  .24091-04             .73994-01  .24091-04  .33556-04  .34416-02
  7              3  .17208+00  .25812+00  .47322-02  .56786-02  .24091-04             .17208+00  .28393-04  .18929-03  .73994-03
  8              1  .23231+00  .34846+00  .63885-02  .12777-02  .32523-04             .99892-01  .32523-04  .45300-04  .46462-02
  8              3  .23231+00  .34846+00  .63885-02  .76662-02  .32523-04             .23231+00  .38331-04  .25554-03  .99892-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .47686+00  .71634+00  .63664-01  .74287-02  .25098-02  .16967-03  .18152+01  .28522-03  .74734-03  .10382-01
  3 BOTTM HOPPER ASH .47759+00 .71634+00  .63664-01  .44603-01  .25098-02  .23816-03  .45025+01  .34085-03  .89464-03  .42038+00

         SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  224 - CYCLONE  BOILERS   >73MW
  2              1  .10002-02  .17810-02  .13981-01  .12928-02  .66681-03  .44741-04  .43880+00  .60228-04  .18154-03  .24952-03
  2              3  .12003-02  .17810-02  .13981-01  .77651-02  .66681-03  .62809-04  .10970+01  .72274-04  .10368-03  .53560-04
  3              1  .74016-02  .13180-01  .10346+00  .95664-02  .49344-02  .33108-03  .32471+01  .44569-03  .13434-02  .18464-02
  3              3  .88819-02  .13180-01  .10346+00  .57462-01  .49344-02  .46479-03  .81179+01  .53482-03  .76722-03  .39634-03
  5              1  .29038-03  .77436-03  .23747-02  .12906-02  .32265-03  .64530-04  .24005+00  .16132-04  .11293-04  .14584-03
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Table B-8. (Continued)

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                                                             POLLUTANTS (GIGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR      NI         V          ZN         ZR         AS         BI         AL         SB         CD         SE

  5              3    .34846-03  .77436-03  .23747-02  .77436-02  .32265-03  .90342-04  .60013+00  .19359-04  .64530-05  .31362+01
  6              1    .86040-02  .12906-01  .23661-03  .47322-04  .12046-05             .36997-02  .12046-05  .16778-05  .17208-03
  6              3    .86040-02  .12906-01  .23661-03  .28393-03  .12046-05             .86040-02  .14197-05  .94644-05  .36997-04
  7              1    .25812-01  .38718-01  .70983-03  .14197-03  .36137-05             .11099-01  .36137-05  .50333-05  .51624-03
  7              3    .25812-01  .38718-01  .70983-03  .85180-03  .36137-05             .25812-01  .42590-05  .28393-04  .11099-03
  8              1    .34416-01  .51624-01  .94644-03  .18929-03  .48182-05             .14799-01  .48182-05  .67111-05  .68832-03
  8              3    .34416-01  .51624-01  .94644-03  .11357-02  .48182-05             .34416-01  .56786-05  .37858-04  .14799-03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .77524-01  .11898+00  .12171+00  .12528-01  .59335-02  .44035-03  .39556+01  .53168-03  .15497-02  .36184-02
  3 BOTTM HOPPER ASH  .79263-01  .11898+00  .12171+00  .75242-01  .59335-02  .61794-03  .98838+01  .63781-03  .95307-03  .31369+01

        SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  225 - VERTICAL/STOKER      >73MW
  1              1    .11512-02  .36008-03  .76145-03  .44268-03  .22973-03  .22973-05             .22973-05  .32265-05  .12906-04
  1              3    .13809-02  .36008-03  .76145-03  .26586-02  .22973-03  .32265-05             .27619-05  .18456-05  .27619-05
  2              1    .60013-03  .10686-02  .83889-02  .77565-03  .40009-03  .26844-04  .26328+00  .36137-04  .10893-03  .14971-03
  2              3    .72015-03  .10686-02  .83889-02  .46591-02  .40009-03  .37686-04  .65821+00  .43364-04  .62207-04  .32136-04
  3              1    .60013-03  .10686-02  .83889-02  .77565-03  .40009-03  .26844-04  .26328+00  .36137-04  .10893-03  .14971-03
  3              3    .72015-03  .10686-02  .83889-02  .46591-02  .40009-03  .37686-04  .65821+00  .43364-04  .62207-04  .32136-04
  5              1    .19359-04  .51624-04  .15831-03  .86040-04  .21510-04  .43020-05  .16003-01  .10755-05  .75285-06  .97225-05
  5              3    .23231-04  .51624-04  .15831-03  .51624-03  .21510-04  .60228-05  .40009-01  .12906-05  .43020-06  .20908+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .23708-02  .25489-02  .17698-01  .20800-02  .10514-02  .60288-04  .54257+00  .75646-04  .22183-03  .32205-03
  3 BOTTM HOPPER ASH  .28445-02  .25489-02  .17698-01  .12493-01  .10514-02  .84620-04  .13564+01  .90781-04  .12669-03  .20914+00

        SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  226 - WALL FIRED - WET   >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

        SECTOR    2 - INDUSTRIAL BOILERS               EQUIPMENT TYPE  227 - OPPOSED WALL - WET >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

SECTOR    2 TOTAL     .34348+02  .51532+02  .63232+01  .24463+01  .26774+00  .20963-01  .32020+03  .30708-01  .76742-01  .58018+01


   BY FUEL --
  1 ANTHRACITE        .33847-01  .96261-02  .20356-01  .41454-01  .61414-02  .73834-04             .67624-04  .67797-04  .20943-03
  2 EASTERN BITUMIN.  .53251-01  .86202-01  .67670+00  .21920+00  .32274-01  .26027-02  .37167+02  .32065-02  .69024-02  .73344-02
  3 CENTRAL BITUMIN.  .47530-01  .76940-01  .60400+00  .19565+00  .28806-01  .23231-02  .33174+02  .28620-02  .61608-02  .65464-02
  4 WESTERN BITUMIN.  .16724-01  .27072-01  .21252+00  .68840-01  .10136-01  .81738-03  .11672+02  .10070-02  .21677-02  .23034-02
  5 LIGNITE           .10860-02  .26328-02  .80740-02  .15358-01  .10970-02  .26328-03  .14283+01  .60336-04  .30168-04  .53317+01
  6 HIGH S RES. OIL   .84319+00  .12648+01  .23188-01  .16231-01  .11805-03             .60288+00  .12859-03  .54597-03  .10245-01
  7 MED  S RES. OIL   .21510+01  .32265+01  .59152-01  .41407-01  .30114-03             .15380+01  .32803-03  .13928-02  .26135-01
  8 LOW  S RES. OIL   .27705+01  .41557+01  .76188-01  .53332-01  .38787-03             .19809+01  .42250-03  .17939-02  .33661-01
 14 BIT/LIG COAL      .30450+00  .49292+00  .38695+01  .12534+01  .18455+00  .14883-01  .21253+03  .18336-01  .39469-01  .41940-01
 15 RESIDUAL OIL      .28126+02  .42190+02  .77348+00  .54143+00  .39377-02             .20110+02  .42893-02  .18212-01  .34174+00

   BY EFFLUENT STREAMS --
  1 FLUE GAS          .17153+02  .25766+02  .31616+01  .34924+00  .13387+00  .87208-02  .91849+02  .13981-01  .38183-01  .38718+00
  3 BOTTM HOPPER ASH  .17195+02  .25766+02  .31616+01  .20971+01  .13387+00  .12242-01  .22835+03  .16726-01  .38559-01  .54146+01

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Table B-8. (Concluded)

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	NI	V	ZN	ZH	AS	BI	AL	SB	CD	SE
				POLLUTANTS (GIGAGRAMS/YEAR)						
GRAND TOTAL	.95454+02	.14366+03	.65413+02	.22822+02	.30643+01	.25249+00	.35613+04	.31285+00	.69752+00	.24233+03
BY FUEL --										
1 ANTHRACITE	.11994+00	.34111-01	.72135-01	.14690+00	.21763-01	.26164-03		.23964-03	.24025-03	.74214-03
2 EASTERN BITUMIN.	.20913+01	.33854+01	.26576+02	.86086+01	.12675+01	.10222+00	.14596+04	.12593+00	.27108+00	.28804+00
3 CENTRAL BITUMIN.	.18664+01	.30213+01	.23718+02	.76829+01	.11312+01	.91224-01	.13027+04	.11239+00	.24193+00	.25707+00
4 WESTERN BITUMIN.	.65530+00	.10608+01	.83274+01	.26974+01	.39715+00	.32028-01	.45737+03	.39459-01	.84939-01	.90256-01
5 LIGNITE	.49000-01	.11879+00	.36428+00	.69292+00	.49495-01	.11879-01	.64442+02	.27222-02	.13611-02	.24055+03
6 HIGH S RES. OIL	.92235+01	.13835+02	.25365+00	.17755+00	.12913-02		.65948+01	.14066-02	.59722-02	.11207+00
7 MED S RES. OIL	.23128+02	.34691+02	.63601+00	.44521+00	.32379-02		.16536+02	.35270-02	.14975-01	.28100+00
8 LOW S RES. OIL	.29890+02	.44835+02	.82198+00	.57539+00	.41846-02		.21372+02	.45583-02	.19354-01	.36317+00
14 BIT/LIG COAL	.30450+00	.49292+00	.38695+01	.12534+01	.18455+00	.14883-01	.21253+03	.18336-01	.39469-01	.41940-01
15 RESIDUAL OIL	.28126+02	.42190+02	.77348+00	.54143+00	.39377-02		.20110+02	.42893-02	.18212-01	.34174+00

Table B-9. Trace Specie Emissions by Equipment Type and Fuel -- 1977

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FUEL -CNTRL FAC- EFF                                      POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       P          SR

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
  6                1                 .11925-02
  6                3   .22998-02  .73254-01
  7                1                 .29873-02
  7                3   .57612-02  .18351+00
  8                1                 .38606-02
  8                3   .74455-02  .23715+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .80404-02
  3 BOTTM HOPPER ASH   .15507-01  .49391+00

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  102 - WALL FIRED BOILER
  6  .09           1                 .11925-02
  6  .09           3   .22998-02  .73254-01
  7  .09           1                 .29933-02
  7  .09           3   .57729-02  .18388+00
  8  .09           1                 .38606-02
  8  .09           3   .74455-02  .23715+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .80465-02
  3 BOTTM HOPPER ASH   .15518-01  .49428+00

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
  6  .26           1                 .48182-03
  6  .26           3   .92923-03  .29598-01
  7  .26           1                 .12046-02
  7  .26           3   .23231-02  .73994-01
  8  .26           1                 .15599-02
  8  .26           3   .30084-02  .95823-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .32463-02
  3 BOTTM HOPPER ASH   .62607-02  .19941+00

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  104 - CYCLONE BOILER
  6                1                 .66251-04
  6                3   .12777-03  .40697-02
  7                1                 .15659-03
  7                3   .30200-03  .96193-02
  8                1                 .21080-03
  8                3   .40654-03  .12949-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .43364-03
  3 BOTTM HOPPER ASH   .83631-03  .26638-01

          SECTOR    1 - UTILITY BOILERS                 EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
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Table B-9. (Continued)

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FUEL -CNTRL FAC- EFF                                          POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       P         SR

           SECTOR    1 - UTILITY BOILERS                   EQUIPMENT TYPE  106 - FRONT WALL FIRING, WET
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

           SECTOR    1 - UTILITY BOILERS                   EQUIPMENT TYPE  107 - HORIZONTALLY OPPOSED,WET
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

SECTOR    1 TOTAL
                       .38122-01  .12340+01

   BY FUEL --
  6 HIGH S RES. OIL    .56567-02  .18311+00
  7 MED  S RES. OIL    .14159-01  .45834+00
  8 LOW  S RES. OIL    .18306-01  .59257+00

   BY EFFLUENT STREAMS --
  1 FLUE GAS                      .19767-01
  3 BOTTM HOPPER ASH   .38122-01  .12142+01

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           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  201 - PKG WALLFIRED WT 29-73MW
 15                 1             .21803-02
 15                 3  .42048-02  .13393+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                      .21803-02
  3 BOTTM HOPPER ASH   .42048-02  .13393+00

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  202 - PKG STOKER W-T   29-73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29MW
 15                 1             .20417-02
 15                 3  .39376-02  .12542+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                      .20417-02
  3 BOTTM HOPPER ASH   .39376-02  .12542+00

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29MW
 15                 1             .10480-02
 15                 3  .20211-02  .64375-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                      .10480-02
  3 BOTTM HOPPER ASH   .20211-02  .64375-01

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29MW
 15                 1             .67455-03
 15                 3  .13009-02  .41437-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                      .67455-03
  3 BOTTM HOPPER ASH   .13009-02  .41437-01

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  206 - STOKER WATER TUBE  <29MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

           SECTOR    2 - INDUSTRIAL BOILERS                EQUIPMENT TYPE  208 - CAST IRON BOILERS
 15                 1             .28307-02
 15                 3  .54592-02  .17389+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                      .28307-02
  3 BOTTM HOPPER ASH   .54592-02  .17389+00
```

Table B-9. (Continued)

```
FUEL -CNTRL FAC- EFF                                 POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       P          SR

             SECTOR     2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  210 - HRT BOILER          <29MW
 15                 1                .40955-03
 15                 3    .78985-03  .25158-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .40955-03
  3 BOTTM HOPPER ASH     .78985-03  .25158-01

             SECTOR     2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
 15                 1                .65950-03
 15                 3    .12719-02  .40512-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .65950-03
  3 BOTTM HOPPER ASH     .12719-02  .40512-01

             SECTOR     2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  221 - TANGENTIAL BOILERS >73MW
  6                 1                .12046-03
  6                 3    .23231-03  .73994-02
  7                 1                .30716-03
  7                 3    .59239-03  .18869-01
  8                 1                .39148-03
  8                 3    .75500-03  .24048-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .81910-03
  3 BOTTM HOPPER ASH     .15797-02  .50316-01

             SECTOR     2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  222 - WALL FIRED - DRY   >73MW
  6                 1                .12046-03
  6                 3    .23231-03  .73994-02
  7                 1                .30716-03
  7                 3    .59239-03  .18869-01
  8                 1                .39148-03
  8                 3    .75500-03  .24048-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .81910-03
  3 BOTTM HOPPER ASH     .15797-02  .50316-01

             SECTOR     2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  223 - OPPOSED WALL - DRY >73MW
  6                 1                .48182-04
  6                 3    .92923-04  .29598-02
  7                 1                .12046-03
  7                 3    .23231-03  .73994-02
  8                 1                .16262-03
  8                 3    .31362-03  .99892-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                         .33125-03
  3 BOTTM HOPPER ASH     .63885-03  .20348-01
```

Table B-9. (Concluded)

```
FUEL -CNTRL FAC- EFF                                     POLLUTANTS (GIGAGRAMS/YEAR)
TYPE  1   2   3  STR       P          SR

         SECTOR    2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  224 - CYCLONE  BOILERS   >73MW
  6              1                 .60228-05
  6              3   .11615-04  .36997-03
  7              1                 .18068-04
  7              3   .34846-04  .11099-02
  8              1                 .24091-04
  8              3   .46462-04  .14799-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                       .48182-04
  3 BOTTM HOPPER ASH   .92923-04  .29598-02

         SECTOR    2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  225 - VERTICAL/STOKER    >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

         SECTOR    2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  226 - WALL FIRED - WET   >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

         SECTOR    2 - INDUSTRIAL BOILERS              EQUIPMENT TYPE  227 - OPPOSED WALL - WET >73MW
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

SECTOR    2 TOTAL
                       .22877-01  .74052+00

   BY FUEL --
  6 HIGH S RES. OIL    .56915-03  .18424-01
  7 MED  S RES. OIL    .14519-02  .46999-01
  8 LOW  S RES. OIL    .18701-02  .60535-01
 15 RESIDUAL OIL       .18985-01  .61456+00

   BY EFFLUENT STREAMS --
  1 FLUE GAS                      .11862-01
  3 BOTTM HOPPER ASH   .22877-01  .72866+00

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -

GRAND TOTAL
                       .60998-01  .19745+01

   BY FUEL --
  6 HIGH S RES. OIL    .62259-02  .20153+00
  7 MED  S RES. OIL    .15611-01  .50534+00
  8 LOW  S RES. OIL    .20176-01  .65310+00
 15 RESIDUAL OIL       .18985-01  .61456+00
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APPENDIX C
EMISSION PROJECTIONS

Energy scenarios were developed as described in this section to approximate the provisions of the National Energy Act and other projected trends in energy use. These scenarios were then combined with emission factor projections based on expected future New Source Performance Standards (NSPS) and used to estimate future emission trends. Since future energy supply and allocation are uncertain, several projections were selected to cover the range of probable developments on energy supply and consumption, and resultant pollutant emissions.

C.1 ENERGY CONSUMPTION SCENARIOS

Three different energy scenarios were considered. Main factors of concern in each alternative were: (1) the effect of government regulations and policies on the rate of growth of demand for energy resources, (2) the additions to capacity by fuel type to meet demand and source attrition, and (3) the oil-to-coal and gas-to-coal conversions implemented. The three energy growth alternatives are:

- Reference -- low nuclear
- Conservation
- Reference -- high nuclear

Table C-1 compares suggested fuel consumption data for each of these scenarios for the year 2000. The reference high and low nuclear cases are provided to bound the range of possible uncertainties in the conservation case. Thus, these alternatives encompass a variety of contingencies in both total demand and demand for specific fuels which lead to important differences in the type and quantity of pollutants released.

These energy scenarios were developed primarily from the DOE Midterm Analysis Report and two EPRI documents (References C-1 through C-3). The DOE report was used because of its recent analysis of the National Energy Act. The two EPRI reports provide alternative energy growth scenarios. All three studies were used because of the technical expertise, the high visibility, and wide circulation of these results. The following three subsections describe these scenarios.

Table C-1. Fuel Use in 2000 Under Three Scenarios (EJ)

Fuel Use Sector	Fuel	Reference -- Low Nuclear	Conservation	Reference -- High Nuclear
Utility Boilers	Coal	62.4	45.0	40.5
	Oil	6.6	2.2	6.5
	Gas	5.5	0.1	5.5
	Total	74.5	47.3	52.5
All Sectors	Coal	64.3	48.7	42.4
	Oil	23.8	11.3	23.8
	Gas	19.4	16.1	19.3
	Total	107.5	76.1	85.5

C.1.1 Conservation Scenario

This case emphasizes conservation practices, resulting in the lowest total fuel use of all three scenarios. The projections are based on the provisions of the National Energy Act, which indicates greater dependence on coal, less dependence on energy imports, and a continued increase in energy prices. Decontrol of domestic crude oil prices, by 1981, is considered in the analysis. Petroleum imports are decreased by encouraging industry and utility sources to switch to coal, prohibiting new oil- and gas-fired boilers, increasing domestic oil production, and reducing overall demand through conservation.

In the year 2000, the conservation case places a heavy emphasis on coal, with very little oil and gas used by the utility sector. Coal use is slightly higher than the reference -- high nuclear case, but total fossil fuel use is lower due to conservation. Net energy consumption by the end-use sectors grows at 1.8 percent annually over the midterm, compared with the 2.6 percent annual rate experienced between 1962 and 1977. Energy consumed in electricity production increases at an annual rate of 4.0 percent over the midterm.

This forecast is a likely representation of future energy developments, but it depends on many underlying assumptions. If the provisions of the National Energy Act are not followed, this forecast may not be realized. Therefore, two reference scenarios were developed to bound the uncertainties inherent in the conservation case.

C.1.2 Reference Cases -- High and Low Nuclear

These two cases represent a baseline overall energy growth, with two different coal/nuclear utility fuel mix scenarios. The reference cases assume that current consumption patterns continue with no major design or efficiency improvements in the residential, commercial, and industrial sectors. The end-use sectors' consumption of energy is derived from the baseline scenario of an econometric model which assumes that the most likely energy prices will prevail, and that no significant new conservation policies are adopted.

The growth in electric demand is high, with electric generation capacity growing at between 5 and 6 percent per year. Coal and nuclear will meet most of the electric demand, with synfuels, oil, and gas contributing a small fraction.

In the low nuclear case, there is a heavy emphasis on utility coal use, and no new nuclear capacity projected after 1985. In 2000, coal will contribute 60 percent to total electricity generation and nuclear only 16 percent. For all sectors, this case is projected to use 41 percent more fossil fuels than the conservation case. This scenario would occur if there were increased pressure to use our coal resources to meet future energy demand and if construction of nuclear power plants continues to be slow.

In the high nuclear scenario, nuclear power plants are projected to supply 40 percent of the utility sectors' electric generation by the year 2000. This case uses slightly less coal than the conservation case, and consumes 12 percent more fossil fuel overall.

C.2 NEW SOURCE PERFORMANCE STANDARDS (NSPS) SCENARIO

The methodology for projecting emissions into the future included consideration of environmental regulations promulgated through the New Source Performance Standards (NSPS). NSPS are based on emission reductions that have been adequately demonstrated. Thus, they are reviewed and revised periodically to reflect advances in current control technologies.

The NSPS scenario assumed here is shown in Table C-2. This scenario was based on the projected capabilities of the developing control technologies discussed in Section 4, and agrees with projected control levels achievable used in the systems analysis calculations discussed in Section 5.

C.3 EMISSION PROJECTIONS

This section presents NO_x emission inventories for the years 1985 and 2000 resulting from stationary combustion sources of NO_x for the reference and conservation scenarios. These inventories are based on uncontrolled emission factors derived as discussed in Appendix B, projected fuel consumption data from Section C.1, and control projections from Section C.2.

The emission projections developed for specific stationary sources consider four major influences:

- Growth (or decline) in energy consumption
- Replacing obsolete sources
- Fuel switching
- Applying NSPS

Energy consumption from new source combustion, from replacing obsolete sources, and from switching from other fuels to coal must comply with new source controls. These influences on emission projections are incorporated in the total emissions projections developed here.

Tables C-3 through C-6 present summaries of annual NO_x emissions by fuel type for 1985 and 2000, for the alternative energy growth scenarios, incorporating the NSPS levels shown in Table C-2. NO_x levels for stationary sources increase by about 10 percent in the conservation scenario from 1977 to 1985, and about 27 percent from 1977 to 2000.

Table C-2. Estimated Future NO_x NSPS Levels

Equipment Types	Fuel	Date Standard Set	Date Effective	Standard (ng/J)
Utility Boilers	Bituminous Coal	1971	1976	301
	Eastern and Central Bituminous Coal	1978	1983	258
	Western Bituminous Coal	1978	1983	215
	Lignite	1978	1983	340
	All Coal	1982	1987	172
		1986	1991	129
		1990	1995	86
	Distillate and Residual Oil	1971	1976	129
	Natural Gas	1971	1976	86
Field Erected Industrial Boilers >73 MW	Bituminous coal	1971	1976	301
		1978	1983	258
		1982	1987	215
	All Coal	1986	1991	172
		1990	1995	129
	Distillate and Residual Oil	1971	1976	129
		1978	1983	150
		1982	1987	129
	Natural Gas	1971	1976	129
		1978	1983	86
Large Packaged Boilers >29 MW	Bituminous and Lignite Coal	1980	1982	172
		1984	1986	129
	Distillate and Residual Oil	1980	1982	150
		1984	1986	129
	Natural and Process Gas	1980	1982	86

Table C-2. Concluded

Equipment Types	Fuel	Date Standard Set	Date Effective	Standard (ng/J)
Small Packaged Boilers <29 MW	Bituminous and Lignite Coal	1984	1986	129
	Distillate and Residual Oil	1984	1986	129
	Natural and Process Gas	1984	1986	86
Small Commercial and Residential Units	Distillate and Residual Oil	1984	1985	30
	Natural gas	1984	1985	17
Gas Turbines	Distillate Oil and Natural Gas	1978 1984	1979 1985	129 86
Reciprocating IC Engines	Distillate Oil and Dual Fuel	1979 1985	1980 1986	1390 1040
	Natural Gas	1979 1985	1980 1986	1240 930
	Gasoline	1979 1985	1980 1986	950 710
Process Combustion	--	1981	1983	20% Reduction
		1990	1992	40% Reduction

Table C-3. Summary of Total NO_x Emissions from Fuel Combustion Sources (1985 Conservation Scenario)

Sector	NO_x Emissions[a] Gg/yr (% of Total)			Total by Sector (% of Total)	Cumulative (%)
	Coal	Oil	Gas		
Utility Boilers	6187 (57.4)	453 (4.2)	143 (1.3)	6783 (62.9)	62.9
Industrial Boilers[b]	408 (3.8)	479 (4.4)	657 (6.1)	1544 (14.3)	77.2
Warm Air Furnaces	--	67 (0.6)	143 (1.3)	210 (1.9)	79.1
Gas Turbines	--	146 (1.4)	75 (0.7)	221 (2.1)	81.2
Reciprocating IC Engines	--	402[c] (3.7)	1123[d] (10.4)	1525 (14.1)	95.3
Process Heating	--	--	--	505 (4.7)	100.0
Total by Fuel	6595 (61.2)	1547 (14.3)	2141 (19.8)	10788 (100.0)	

[a] NO_2 basis

[b] Includes large industrial boilers >73 MW, and steam and hot water commercial and residential units

[c] Includes gasoline

[d] Includes dual fuels (oil and gas)

Table C-4. Summary of Total NO_x Emissions from Fuel Combustion Sources (2000 Conservation Scenario)

Sector	NO_x Emissions[a] Gg/yr (% of Total)			Total by Sector (% of Total)	Cumulative (%)
	Coal	Oil	Gas		
Utility Boilers	8094 (64.9)	334 (2.7)	20 (0.2)	8448 (67.8)	67.8
Industrial Boilers[b]	781 (6.3)	580 (4.6)	588 (4.7)	1949 (15.6)	83.4
Warm Air Furnaces	--	59 (0.5)	127 (1.0)	186 (1.5)	84.9
Gas Turbines	--	175 (1.4)	114 (0.9)	289 (2.3)	87.2
Reciprocating IC Engines	--	436[c] (3.5)	571[d] (4.6)	1007 (8.1)	95.3
Process Heating	--	--	--	591 (4.7)	100.0
Total by Fuel	8875 (71.2)	1584 (12.7)	1420 (11.4)	12470 (100.0)	

[a] NO_2 basis
[b] Includes large industrial boilers >73 MW, and steam and hot water commercial and residential units
[c] Includes gasoline
[d] Includes dual fuels (oil and gas)

Table C-5. Summary of Total NO_x Emissions from Fuel Combustion Sources (2000 Low Nuclear Scenario)

Sector	NO_x Emissions[a] Gg/yr (% of Total)			Total by Sector (% of Total)	Cumulative (%)
	Coal	Oil	Gas		
Utility Boilers	10124 (64.3)	870 (5.6)	558 (3.5)	11552 (73.4)	73.4
Industrial Boilers[b]	428 (2.7)	934 (5.9)	719 (4.6)	2081 (13.2)	86.6
Warm Air Furnaces	--	144 (0.9)	76 (0.5)	220 (1.4)	88.0
Gas Turbines	--	175 (1.1)	114 (0.7)	289 (1.8)	89.8
Reciprocating IC Engines	--	436[c] (2.8)	571[d] (3.6)	1007 (6.4)	96.2
Process Heating	--	--	--	591 (3.8)	100.0
Total by Fuel	10552 (67.0)	2559 (16.3)	2038 (12.9)	15740 (100.0)	

[a] NO_2 basis

[b] Includes large industrial boilers >73 MW, and steam and hot water commercial and residential units

[c] Includes gasoline

[d] Includes dual fuels (oil and gas)

Table C-6. Summary of Total NO_x Emissions from Fuel Combustion Sources (2000 High Nuclear Scenario)

Sector	NO_x Emissions[a] Gg/yr (% of Total)			Total by Sector (% of Total)	Cumulative (%)
	Coal	Oil	Gas		
Utility Boilers	7505 (57.2)	866 (6.6)	554 (4.2)	8925 (68.0)	68.1
Industrial Boilers[b]	428 (3.3)	934 (7.1)	719 (5.5)	2081 (15.9)	83.9
Warm Air Furnaces	--	144 (1.1)	76 (0.6)	220 (1.7)	85.6
Gas Turbines	--	175 (1.4)	114 (0.8)	289 (2.2)	87.8
Reciprocating IC Engines	--	436[c] (3.3)	571[d] (4.4)	1007 (7.7)	95.5
Process Heating	--	--	--	591 (4.5)	100.0
Total by Fuel	7933 (60.5)	2555 (19.5)	2034 (15.5)	13113 (100.0)	

[a] NO_2 basis

[b] Includes large industrial boilers >73 MW, and steam and hot water commercial and residential units

[c] Includes gasoline

[d] Includes dual fuels (oil and gas)

Utility and industrial boilers account for most of the increase. Under the conservation case, NO_x emissions from utility and industrial boilers increase by about 20 percent from 1977 to 1985, and 50 percent from 1977 to 2000.

The reference high and low nuclear scenarios provide bounds for the uncertainties in the conservation case. If nuclear growth is retarded total NO_x emissions in year 2000 may be more than 25 percent higher than the conservation case. Corresponding utility NO_x emissions may be over 35 percent higher than the conservation case for the low nuclear case. This greatly increased coal use will cause NO_x emissions to increase in the year 2000 by 60 percent over the 1977 levels, compared with 27 percent for the conservation case.

The lower bound for the conservation scenario is provided by the reference high nuclear scenario. Actually, the total year 2000 emission levels from this scenario closely resemble the conservation case, except that the latter assumes greater switching of industrial and commercial boilers to coal. Tables C-4 and C-6 show little difference in emission levels for utility and industrial boilers between the conservation and high nuclear reference cases.

C.4 EQUIPMENT/FUEL EMISSIONS RANKING

Specific stationary source types are ranked in this section according to their contribution to projected NO_x emissions. Table C-7 ranks equipment/fuel combinations by annual NO_x emissions for year 2000 for the conservation scenario. Although about 90 equipment/fuel combinations were inventoried, the 15 most significant combinations account for over 75 percent of total NO_x in the year 2000 for this scenario. The ranking of specific equipment/fuel types depends both on the total installed capacity as well as projected emission factor. A high rank therefore does not necessarily imply that a specific source type is a high emitter; a large installed capacity can lead to a high rank.

Comparing Table C-7 to Table B-4 in Appendix B, it is seen that coal-fired stationary sources increase their share of NO_x emissions and dominate the highest rankings through the year 2000. Of the coal-fired equipment types, utility boilers remain the major emissions sources. Coal-fired tangential boilers appear to be the most significant NO_x source through the year 2000 under the conservation scenario. Because of

Table C-7. NO_x[a] Mass Emission Ranking of Stationary Combustion Equipment for Year 2000 Conservation Scenario

Rank	Sector	Equipment Types	Fuel	Annual NO_x (Gg)	Cumulative (Gg)	Cumulative (percent)	1977 Rank	1985 Rank
1	Utility boilers	Tangential	Coal	4057.1	4057.1	32.5	1	1
2	Utility boilers	Opposed wall (dry)	Coal	2310.5	6367.6	51.1	7	2
3	Utility boilers	Wall firing (dry)	Coal	673.5	7041.1	56.5	4	4
4	Utility boilers	Cyclone	Coal	501.0	7542.1	60.5	2	3
5	Utility boilers	Wall firing (wet)	Coal	387.8	7929.0	63.6	5	5
6	Industrial boilers	Stoker watertube <29 MW[b]	Coal	287.8	8217.7	65.9	>15	14
7	Reciprocating IC engines	75 kW to 75 kW/cyl[c]	Gas	267.2	8484.9	68.0	3	6
8	Reciprocating IC engines	>75 kW/cyl[c]	Gas	262.1	8744.0	70.1	6	7
9	Reciprocating IC engines	75 kW to 75 kW/cyl[c]	Oil[d]	245.4	8992.4	72.1	10	8
10	Industrial process	Glass melting furnaces	Process material	174.2	9166.6	73.5	>15	13
11	Utility boilers	Wall firing (dry)	Oil	143.4	9310.0	74.7	8	9
12	Industrial boilers	Tangential >73 MW[b]	Coal	127.3	9437.3	75.7	>15	>15
13	Industrial process	Cement kilns	Process material	123.9	9561.2	76.7	>15	>15
14	Industrial boilers	Single burner W-T <29 MW[b]	Gas	116.3	9677.5	77.6	>15	>15
15	Utility boilers	Tangential	Oil	114.1	9791.6	78.5	12	11

[a] NO_2 basis

[b] Heat input

[c] Power output

[d] Includes distillate and gasoline

the conservation scenario's emphasis on coal use in the industrial sector, watertube stokers also show significant increases in NO_x levels through year 2000. For example, in 1977, watertube stokers (29 MW) were not ranked in the top 15 sources nationally. In year 2000, under the conservation scenario, stokers could potentially be the sixth most important NO_x source.

Natural gas-fired combustion sources show increasingly lower NO_x emission rankings through year 2000 due to projected decreases in natural gas use in the conservation scenario. For example, in year 2000 the highest natural gas-fired source is seventh on the ranking, compared to third in 1977. Oil-fired sources also show a gradual decrease in total NO_x emissions due to source attrition and replacement with coal-fired sources.

It should be noted that these rankings are based on projected equipment fuel consumption, growth rates, and NSPS implementation. Because of the uncertainty in these projections, these rankings should be considered only as qualitative indications of future trends, not as quantitative conclusions.

C.5 SUMMARY

In conclusion, energy scenarios were developed in the NO_x EA to approximate a conservation scenario and possible uncertainties in this projection. These scenarios were then used as a basis for estimating NO_x emission trends in stationary combustion sources. Specifically, equipment/fuel combinations were ranked based on the conservation energy scenario, with NSPS enforcement, and estimated single source emission levels. These rankings and future emission estimates provide orientation for evaluating the economic and air quality impacts of candidate control strategies. Major results obtained include:

- With the conservation scenario and NSPS implementation, national stationary source NO_x emission levels should increase by about 27 percent by the year 2000. If nuclear growth is not realized NO_x levels may actually increase by as much as 60 percent, even with NSPS implementation.
- Coal-fired combustion sources emerge as the major NO_x generator in the year 2000 time frame. This shift to coal is caused by the provisions in the National Energy Act (NEA) and

the future projected scarcity of natural gas and oil. The NEA encourages coal use through decontrolled prices of oil and prohibitions on new oil- and gas-fired boilers.

- Oil-, and natural gas-fired combustion equipment will be less significant in the year 2000 time frame because coal and nuclear power play a larger role
- Coal-fired utility boilers are the most significant equipment/fuel combination accounting for about 60 percent of total NO_x emissions in year 2000. Of these sources, tangential firing is the major contributor.
- Because of the conservation scenario's increased emphasis on coal firing in the industrial sector, stokers should occupy a larger portion of the industrial sector by the year 2000. This is a result of the NEP "coal substitution program" which should accelerate retirement of existing oil and gas boilers, and replace them with new coal-fired units.

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APPENDIX D

POLLUTANT IMPACT EVALUATION

The multimedia emissions data presented in Appendix B, and the NO_x emission projections presented in Appendix C help to indicate the pollution potential of the various source categories treated. However, the source rankings presented in those Appendices were based solely on emissions and neglected such important factors as population exposure and ambient levels to which exposed. Thus these and other factors were incorporated into a Source Analysis Model (SAM) which was used with the Appendix B multimedia emissions data and the Appendix C NO_x emission projections to estimate the potential impact of source categories. This appendix describes the source analysis model used and the ranking results obtained from its application.

D.1 SOURCE ANALYSIS MODEL DESCRIPTIONS

The model used for source potential impact ranking is more sophisticated than the SAM IA model described in Section 3 and used to evaluate source test results in that pollutant dispersion, ambient impacts, and population exposure are incorporated. However, it should be noted that only gaseous discharges are evaluated here, whereas SAM IA can also treat liquid and solid effluents.

The model developed for impact ranking is based on the hypothesis that the impact of a particular type of pollutant source is directly proportional to: (1) the ground level concentration of pollutant species due to a single source compared to an impact threshold limit, (2) the number of people exposed to that concentration from a single source, and (3) the total number of sources of that type nationwide. In this respect, it is similar to other models (Reference D-1), but differs in the specific manner in which population exposure and background ambient pollutant concentration are treated. In addition, the SAM makes more direct use of available data. With the model, simple dispersion calculations for gaseous streams can easily be done.

Using the source impact hypothesis described above, the impact of the gaseous effluent streams from all sources of type i can be defined as:

$$I_i = \sum_j P_j \sum_k \int \chi_{jk}/\chi_k^A dA$$

where
I_i = impact due to all sources of type i (e.g., bituminous coal-fired tangential boilers)
j = an index identifying each of the individual sources
P_j = population density near source j
k = index identifying each pollutant species (e.g., NO_2)
χ_{jk} = ground level concentration of species k due to source j
χ_k^A = permissible ground level concentration of species k (i.e., concentration below which adverse health effects are negligible)
dA = an element of area near the source

This definition, then, ascribes a high impact factor to sources that expose many people to high pollutant concentrations. Because detailed input data are required, a direct calculation of this factor for all combustion sources is not always possible. However, the problem can be made manageable by approximations. These approximations are described as the equation is discussed below. Both point sources and distributed (or area) sources are discussed.

It should be noted that a key aspect of any model of this type is the definition of allowable ground level concentrations, the χ^A. The most recent and complete lists of these values are the ambient concentration Multimedia Environmental Goals (Reference D-2). Thus, these are the ones employed in the present model and are denoted χ^{MEG}.

D.1.1 Point Source Model

If reactions between pollutant species are neglected, and uniform topology is assumed, the ground level concentration of a pollutant issuing from a point source of gaseous emissions (χ_{jk}) can be calculated from a Gaussian plume dispersion formula. The pollutant emission rate, the stack height, and meteorological information are the only required inputs (Reference D-3). For the analyses herein, the wind speed (4 m/s) and atmospheric stability class (D) were assumed constant for all sources and locations. These values represent averages across the nation and throughout the year.

Given the meteorological data above and an assumed mixing height of 1500 m, the ground level concentration along the plume centerline, χ_{jk}, normalized with the source emission rate for species k, Q_{jk}, can be plotted as a function of distance from the source as shown in Figure D-1. Each curve represents one value of the stack height, H. These curves can be easily generated numerically and, given the assumptions above, require only effective stack height as an input parameter. Once the ratio χ_{jk}/Q_{jk} is determined, the ground level concentration is found by multiplying the ratio by the pollutant emission rate, Q_{jk}.

To determine the impact factor, the integral

$$\int \chi_{jk}/\chi_k^{MEG} \, dA$$

must be evaluated. However, this poses two problems. The first problem is that in the discussion above, a method for calculating the plume centerline concentration is given, but results are not given for off-centerline concentrations. The second problem is defining the limits of the integration.

The problem of off-centerline concentrations is solved by assuming that the ground level concentration is a function only of the distance from the source, r, and is given by the centerline value in Figure D-1. This assumption is much the same as the assumption that the wind direction is random over time. Using this assumption, the integral can be given in the form

$$2\pi/\chi_k^{MEG} \int_a^b r\chi_{jk}(r)dr$$

where the limits of integration, r = a,b are still undefined. This form of the integral was used in the analyses.

The limits of integration in the above equation might be defined practically by integrating over all areas in which the ground level

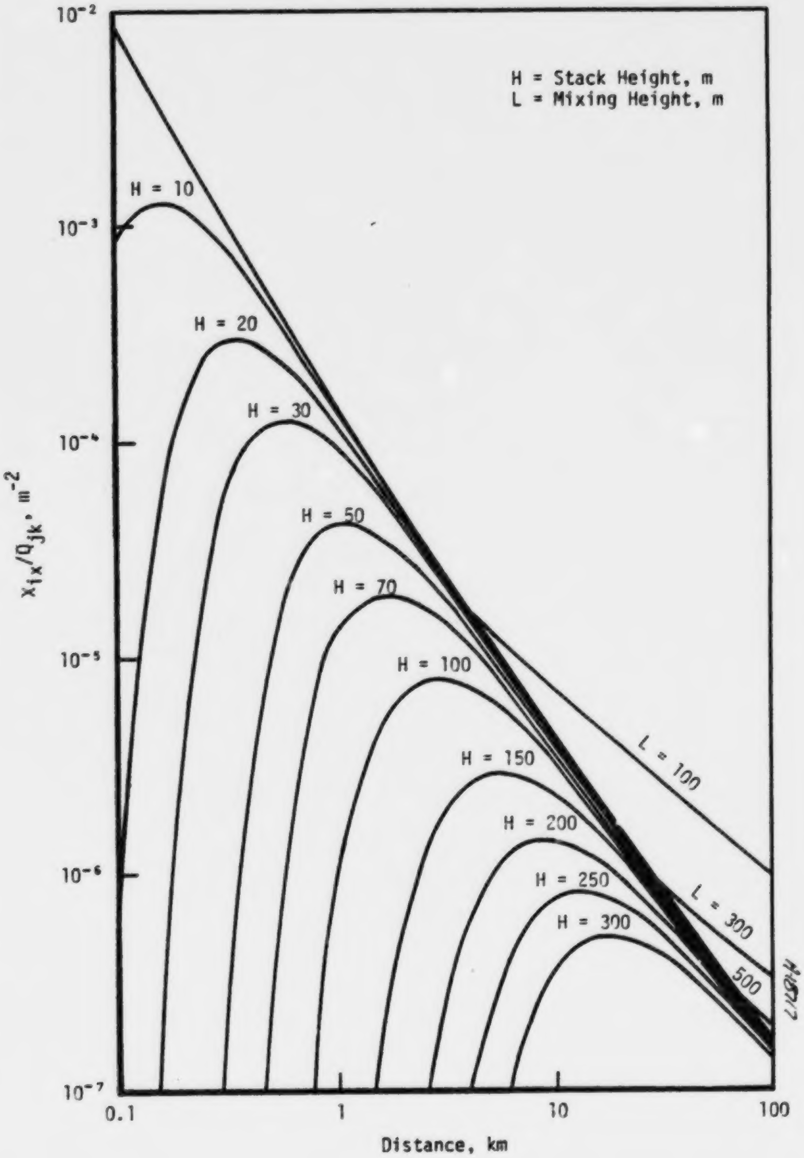

Figure D-1. Ground Level Concentration for a Gaussian Plume for a Uniform Wind Speed of 4 m/s.

concentration exceeds the maximum allowable concentration. This approach assumes that concentrations less than the maximum allowable concentrations, χ_k^{MEG}, are not harmful and should not contribute to the integral. However, this approach places a large dependence on the accuracy of the MEG. To account for possible inconsistencies in the MEGs, a safety factor of 10 was used. Hence, the integral was evaluated over those regions where $\chi_{jk} \geq 0.1\ \chi_k^{MEG}$.

In many areas, the background concentration of a particular pollutant may approach or exceed the concentration (χ_{jk}) due to a single source. Since adding sources in regions with high existing background levels may cause ambient pollutant concentrations which are harmful, the background, χ_k^B, should be included in the definition of the impact factor. The background is included here by replacing the integrand χ_{jk}/χ_k^{MEG} with $(\chi_{jk} + \chi_k^B)/\chi_k^{MEG}$. This approach, although somewhat conservative, was selected because the plume centerline dispersion calculation was made assuming zero background concentration. Use of χ_k^B in the numerator thus compensates for the simplified dispersion calculation. The modified integrand requires that the limits of integration be modified to allow integration over regions where χ_{jk} is less than 0.1 χ_k^{MEG} criteria, but $(\chi_{jk} + \chi_k^B)$ is not. Accordingly, the lower limit of integration (a) is defined as the lesser of the distances at which either: (1)$\chi_{jk} = 0.1\chi_k^{MEG}$, or (2) $(\chi_{jk} + \chi_k^B) = 0.1\chi_k^{MEG}$ and $\chi_{jk} \geq 0.1\chi_k B$.

Similarly, the upper limit (b) is the larger of the distances that satisfy the above conditions. This definition ensures that the integration is performed over regions where either:

a. the ground level concentration due to the source (χ_{jk}) exceeds the impact criteria

b. The resulting ground level concentration (which is the sum of χ_{jk} and the background due to other sources, $\chi_{jk} = \chi_k^B$) exceeds criteria and χ_{jk} constitutes a significant portion (10 percent) of that concentration these criteria are used in the analysis to define the exposed impact area. The value of the integral

$$2\pi/\chi_k^{MEG} \int_a^b \left(\chi_{jk} + \chi_k^B\right) r \, dr$$

Between these two limits gives an indication of the impact of pollutant k from source j.

Just as the integral above indicates the impact of a single pollutant from a particular source, a sum over pollutant species indicates the impact (excluding population density effects) due to all pollutants. Hence, three impact parameters are defined in the form:

$$IP_j^i = \sum_k 2\pi/\chi_k^{MEG} \int_a^b \left(\chi_{jk} + \chi_k^{Bi}\right) r \, dr$$

In regions where there is no natural background (i = N), χ_k^{BN} is zero and $IP\chi_j^N$ represents the impact parameters for source type j in such regions. Similarly, in rural (i = R) and urban (i = U) areas, background concentrations χ_j^R and χ_j^U prevail, respectively, and IP_j^R and IP_j^U represent the impact parameters for source type j in these regions.

Forming the product of the impact parameter with local population density yields the desired quantity, the impact factor:

$$IF_j^i = P_i \cdot IP_j^i$$

Thus, urban and rural total impact factors can be calculated for each source type j.

The impact of all sources of the same type -- some urban and some rural -- can be calculated by:

$$IF_j^T = N_j^R \cdot IF_j^R + N_j^U \cdot IF_j^U$$

where N_j^R N_j^U are the number sources of type j of rural and urban areas, respectively. Such numbers, then, give quantified estimates by which the impacts of sources of different types can be compared.

D.1.2 Distributed Sources

The model described above can also be applied to distributed sources -- sources such as home furnaces whose emission rates are constant over a large area. The basic change in the model is the dispersion calculation.

For distributed sources, a model from Holzworth (Reference D-4) is used which predicts a ground level concentration along the wind direction as:

$$\chi_{jk}/Q_{jk} = 3.994\ x^{0.115} \qquad x \leq 7312\ \text{m}$$

$$\chi_{jk}/Q_{jk} = 9.35 + (8.33 \times 10^{-5})\ x - 3535/x \qquad x > 7312\ \text{m}$$

where

x = downward distance from source edge (m)

χ_{jk} = ambient concentration of species k (g/m^3), due to source type j

Q_{jk} = source emission rate of species k (g/m^2·s), due to source type j

Here the mixing height and wind speed are the same as in the Gaussian model. An analagous impact integral can be put into the form

$$S_{max}/\chi_k^{MEG} \int_a^b \chi_{jk}(x)dx$$

where S_{max} is the maximum length of the source along the wind direction (e.g., the downward city limit). The lower limit of integration is defined in the same way as for point sources; the upper limit (b) is equal to S_{max}. These limits are shown graphically in Figure D-2 where the area for the integration is shown crosshatched.

Again, as with point source, three impact parameters are defined in the form:

$$IP_j^i = \sum_k S_{max}/\chi_k^{MEG} \int_a^b \left(\chi_{jk} + {}_k^{Bi}\right)dx$$

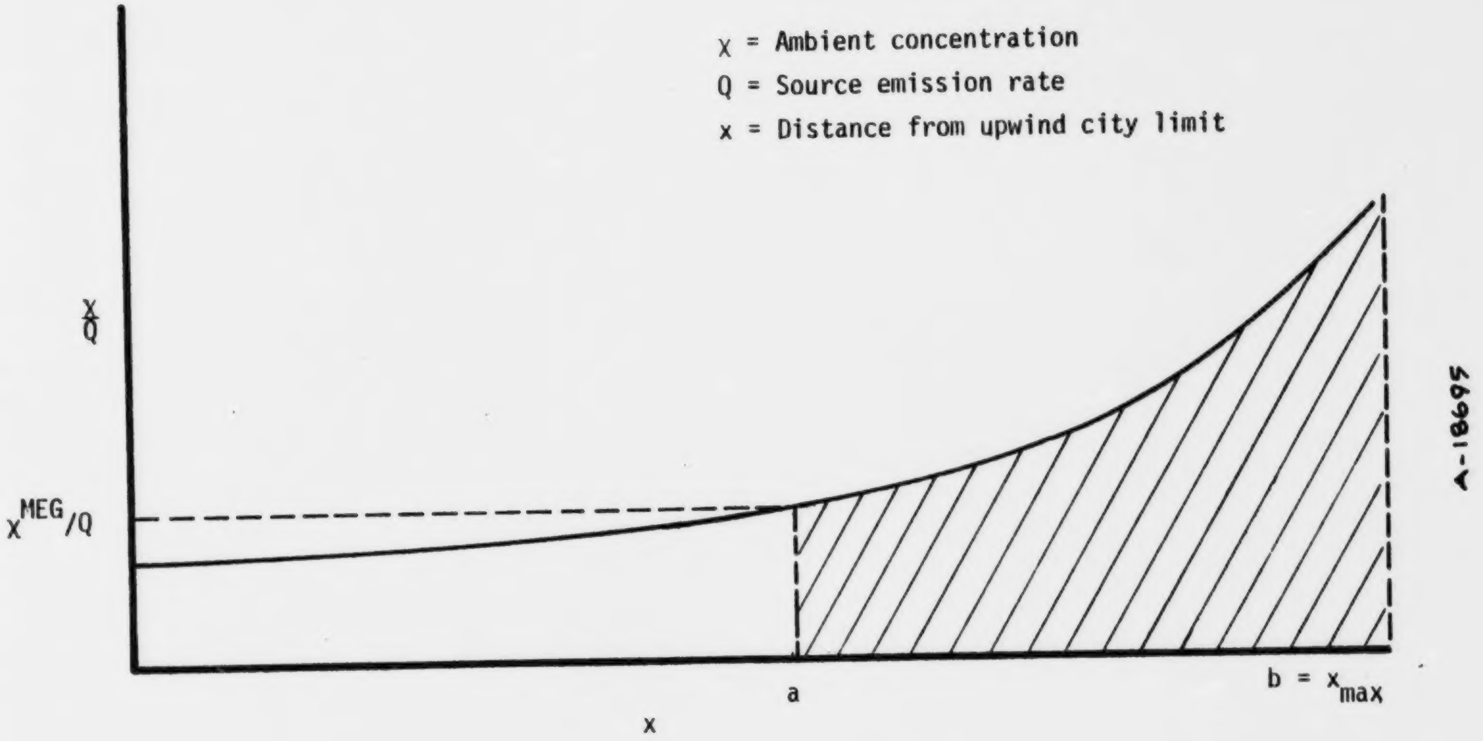

Figure D-2. Limits of Integration For Distributed Sources for impacts in regions with no natural background concentrations (i = N, $\chi_k^{BN} = 0$), in rural areas (i = R), and in urban areas (i = U). these parameters are sums over the integrals of each species with corrections for local background. They are used to generate impact factors in the same way as were the point source impact parameters.

D.2 POTENTIAL IMPACT CALCULATIONS

The model described in Section D.1 was used to rank source categories in terms of a potential impact factor calculated based on multipollutant emissions, and NO_x emissions only. Pollutant emission rates for 1977, given in Appendix B, were used to obtain multipollutant impact rankings, and NO_x impact ranking in 1977. Flue gas pollutants considered for multipollutant rankings included NO_x, SO_x, CO hydrocarbon, particulates, sulfates, trace elements, and polycyclic organic matter (POM). Projected NO_x emission rates (for the conservation scenario), given in Appendix C were used to obtain NO_x impacts in 2000. Other model impacts were obtained as follows:

- Source stack heights were obtained from utility power industry statistics (Reference D-5) for utility boilers, from related survey documents for packaged boilers (References D-6, D-7) and from various industry and trade associations and government agencies for other equipment sectors (References D-8 through D-13).
- Population densities, and urban/rural region designations were defined from EPA and Bureau of Census data (References D-14 through D-16)
- Urban/rural equipment populations were estimated from regional fuel consumption data as reported in the National Emissions Data System (NEDS) (Reference D-17)
- Ambient background pollutant concentrations were obtained from the EPA's Storage and Retrieval of Aerometric Data (SAROAD) system (References D-18 through D-24) for criteria and most noncriteria pollutants. Trace element data were obtained from the published literature (References D-25 through D-30)

The resultant ranking obtained for gaseous multipollutant pollution potential for the 15 most significant sources in 1977 is shown in

Table D-1. Total Potential Impact Ranking of Stationary Sources -- 1977.

Rank	Sector	Equipment Types[a]	Fuel	Total Impact Factor
1	Utility boiler	Tangential	Coal	1.57×10^{11}
2	Industrial boiler	Stoker watertube, <29 MW	Coal	1.57×10^{11}
3	Industrial boiler	Stoker firetube, <29 MW	Coal	1.03×10^{11}
4	Utility boiler	Wall firing (dry)	Coal	7.62×10^{10}
5	Utility boiler	Vertical and stoker	Coal	5.33×10^{10}
6	Utility boiler	Cyclone	Coal	3.87×10^{10}
7	Utility boiler	Opposed wall (dry)	Coal	2.45×10^{10}
8	Industrial boiler	Wall firing watertube, 29-73 MW	Coal	1.77×10^{10}
9	Industrial boiler	Stoker watertube, 29-73 MW	Coal	1.74×10^{10}
10	Industrial boiler	Tangential >73 MW	Coal	3.99×10^{9}
11	Utility boiler	Tangential	Oil	2.65×10^{9}
12	Utility boiler	Wall firing	Oil	2.12×10^{9}
13	Industrial boiler	Opposed wall (dry) >73 MW	Coal	1.68×10^{9}
14	Utility boiler	Wall firing (wet)	Coal	1.47×10^{9}
15	Utility boiler	Opposed wall	Oil	1.08×10^{9}

[a] Equipment capacity ranges as heat input

Table D-2. NO_x Potential Impact Ranking of Stationary Sources -- 1977.

Rank	Sector	Equipment Types[a]	Fuel	NO_x Impact Factor
1	Utility boiler	Cyclone	Coal	4.67×10^8
2	Utility boiler	Tangential	Coal	3.61×10^8
3	Utility boiler	Wall firing (wet)	Coal	2.32×10^8
4	Utility boiler	Opposed wall (dry)	Coal	1.69×10^8
5	Utility boiler	Wall firing (dry)	Coal	1.27×10^8
6	Utility boiler	Opposed wall (wet)	Coal	8.48×10^7
7	Utility boiler	Opposed wall	Gas	6.38×10^7
8	Utility boiler	Tangential	Oil	4.37×10^7
9	Industrial boiler	Opposed wall, >73 MW	Gas	3.54×10^7
10	Utility boiler	Wall firing	Gas	3.12×10^7
11	Utility boiler	Opposed wall	Oil	2.48×10^7
12	IC Engine	Spark ignition, >75 kW/cyl	Gas	2.26×10^7
13	Utility boiler	Wall firing	Oil	2.18×10^7
14	Industrial boiler	Cyclone, >73 MW	Coal	1.49×10^7
15	Industrial boiler	Wall firing, >73 MW	Gas	1.37×10^7

[a] Equipment capacity ranges as heat input

Table D-3. NO_x Potential Impact Ranking of Stationary Sources -- 2000, Conservation Scenario

Rank	Sector	Equipment Types[a]	Fuel	Total Impact Factor	1977 Rank
1	Utility boiler	Tangential	Coal	7.67×10^8	2
2	Utility boiler	Cyclone	Coal	2.63×10^8	1
3	Utility boiler	Wall firing (wet)	Coal	1.25×10^8	3
4	Utility boiler	Wall firing (dry)	Coal	1.16×10^8	5
5	Utility boiler	Opposed wall (dry)	Coal	8.90×10^7	4
6	Utility boiler	Opposed wall (wet)	Coal	4.56×10^7	6
7	Utility boiler	Tangential	Oil	2.99×10^7	8
8	Industrial boiler	Tangential, >73 MW	Coal	2.68×10^7	>15
9	Utility boiler	Opposed wall	Oil	1.95×10^7	11
10	Industrial boiler	Stoker watertube, <29 MW	Coal	1.94×10^7	≥15
11	Industrial boiler	Opposed wall, >73 MW	Gas	1.79×10^7	9
12	Industrial boiler	Tangential, >73 MW	Oil	1.75×10^7	>15
13	Industrial boiler	Wall firing, >73 MW	Gas	1.21×10^7	15
14	Utility boiler	Wall firing	Oil	1.19×10^7	13
15	Gas turbine	Simple cycle, >15 MW	Oil	1.15×10^7	>15

[a] Equipment capacity ranges as heat input

Table D-1. As the table shows, coal-fired sources (utility and industrial boilers) dominate the rankings. Small industrial stokers rank high in part because of relatively poorly controlled particulate emissions and the fact that they are concentrated in urban areas. Large utility sources also rank high, because of high emission rates of all pollutants.

Table D-2 shows the potential impact ranking of sources in 1977 for NO_x emissions only. This rank is dominated by large coal-fired utility boilers. Cyclone boilers rank highest because of their high NO_x emission factors. The only nonboiler source in the 15 potentially most hazardous (based on NO_x) is gas-fired, spark ignition IC engines. Again, this category ranks high because of its high NO_x emission factor.

Table D-3 projects the NO_x potential impact ranking to the year 2000, based on the conservation scenario discussed in Appendix C. Generally the 1977 NO_x potential impact ranking is preserved. Coal-fired cyclone utility boilers fall slightly due to source attrition, while coal-fired tangential utility boilers rise in the ranking due to new capacity additions.

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APPENDIX E

UNIT CONVERSIONS
AND
USEFUL CONVERSIONS

Table E-1. Prefixes for SI Units

The names of multiples and submultiples of SI units may be formed by application of these prefixes:

Factor by Which Unit is Multipled	Prefix	Symbol
10^{18}	exa	E
10^{15}	peta	P
10^{12}	tera	T
10^{9}	giga	G
10^{6}	mega	M
10^{3}	kilo	k
10^{2}	hecto	h
10	deca	da
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p
10^{-15}	femto	f
10^{-18}	atto	a

Table E-2. Unit Conversions (English and Metric Units to SI Units)

To Obtain	From	Multiply By
ng/J	lb/10^6 Btu	430
ng/J	g/10^6 cal	239
MJ/s	10^6 Btu/hr	0.293
J/kg	Btu/lb	2,326
kW/m^2	10^6 Btu/hr-ft^2	3,154
kW/m^3	10^6 Btu/hr-ft^3	10,350
GJ/hr-m^2	10^6 Btu/hr-ft^2	11.356
GJ/hr-m^3	10^6 Btu/hr-ft^3	37.257
GJ/hr	10^3 lb saturated steam/hr	1.055
GJ/hr	10^6 Btu/hr	1.055
kg/s	10^3 lb/hr	0.126
W	hp	746
g/kW-hr	lb/hp-hr	609
kg	lb	0.4536
kg/s	lb/min	0.00758
l/s	gpm	0.0631
ml/s	gph	1.051
μg/m^3	lb/ft^3	1.603 x 10^{10}
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
Pa	iwg (39.2°F)	249.1
Pa	psia	6,895
Pa	psig	Pa = (psig + 14.7)(6,895)
°C (Celcius)	°F	°C = 5/9 (°F - 32)
K (Kelvin)	°F	K = 5/9 (°F - 32) + 273

Table E-3. Useful Conversions

Fuel	To Obtain	Multiply Concentration in ppm dry at 3% O_2 by
Natural gas	ng/J	0.01107 (MW)[a]
	μg/dscm[b] flue gas	41.86 (MW)/K[c]
	mg/kg fuel	0.5781 (MW)
Oil	ng/J	0.01219 (MW)
	μg/dscm[b] flue gas	41.86 (MW)/K
	mg/kg fuel	0.5650 (MW)
Coal	ng/J	0.01329 (MW)
	μg/dscm[b] flue gas	41.86 (MW)/K
	mg/kg fuel	0.4010 (MW)

[a] MW = molecular weight of the pollutant.

[b] dscm = dry standard cubic meter of flue gas at standard atmospheric conditions of 293K (68°F) and 1 atm.

[c] K = [17.9/(20.9 - % O_2 measured)] correction factor used in calculating ppm to 3 percent O_2.

APPENDIX F

FUEL ANALYSES

Table F-1. Kingston No. 6 Coal (Percent by Weight)

Test	Baseline	BOOS I	BOOS II	Bias I	Bias II
Ultimate Analyses					
Moisture	2.04	1.58	2.58	2.34	1.97
Carbon	63.13	64.45	64.00	63.46	68.33
Hydrogen	4.27	4.39	4.28	4.24	4.62
Nitrogen	1.38	1.13	1.38	1.13	1.02
Chlorine	0.55	0.05	0.03	0.02	0.01
Sulfur	2.19	2.40	2.13	1.75	1.75
Ash	19.60	19.26	18.49	19.09	14.59
Oxygen (diff.)	6.84	6.74	7.11	7.97	7.71
Proximate Analyses					
Moisture	2.04	1.58	2.58	2.34	1.97
Ash	19.60	19.26	18.49	19.09	14.59
Volatile	31.84	32.10	31.68	31.86	33.32
Fixed carbon	46.52	47.06	47.25	46.71	50.12
HHV kJ/kg (Btu/lb)	36,288 (11,302)	26,854 (11,545)	26,521 (11,402)	26,363 (11,334)	28,484 (12,246)

Table F-2. Crist No. 7 Coal

Test	Baseline	BOOS 1	BOOS 2
Ultimate Analyses (percent by weight):			
Moisture	7.64	8.48	8.07
Ash	16.48	12.45	14.32
Carbon	59.62	62.18	61.61
Hydrogen	4.27	4.37	4.09
Nitrogen	1.12	1.14	1.12
Chlorine	0.05	0.08	0.05
Sulfur	3.70	3.89	3.39
Oxygen (diff.)	7.12	7.41	7.35
Proximate Analyses (percent by weight):			
Moisture	7.64	8.48	8.07
Volatile matter	33.00	34.47	33.43
Ash	16.48	12.45	14.32
Fixed carbon	42.88	44.60	44.18
HHV kJ/kg (Btu/lb)	25,055 (10,782)	26,173 (11,263)	25,638 (11,033)
Ash Analysis (percent by weight):			
SiO_2	45.63	40.25	44.93
Al_2O_3	21.21	18.38	21.05
TiO_2	0.90	0.81	0.89
Fe_3O_4	18.08	27.58	18.02
CaO	3.84	3.68	3.85
MgO	1.01	0.87	1.03
K_2O	2.67	2.35	2.65
Na_2O	0.31	0.48	0.32
SO_3	4.63	4.83	4.76
P_2O_5	0.27	0.19	0.28
SrO	0.00	0.00	0.00
BaO	0.07	0.03	0.07
Mn_3O_4	0.06	0.09	0.06

Table F-3. Moss Landing No. 6 Oil

Test	Baseline	BOOS/FGR	FGR
Ultimate Analyses (percent by weight):			
Moisture	0.9	0.8	0.95
Carbon	84.25	84.26	84.44
Hydrogen	12.05	12.11	11.97
Nitrogen	0.25	0.23	0.27
Sulfur	0.21	0.25	0.31
Ash	0.05	0.05	0.05
Oxygen (diff.)	2.29	2.30	2.01
HHV (kJ/kg) (Btu/lb)	43,300 (18,600)	43,900 (18,900)	43,200 (18,600)
Specific gravity	0.900	0.898	0.907

Table F-4. Site A Coal

Test	Baseline	Low NOx	
Ultimate Analysis (percent by weight):			(Replicate)
Moisture	13.76	14.58	(9.21)
Carbon	60.87	60.06	(62.48)
Hydrogen	4.27	4.12	(4.22)
Nitrogen	0.97	0.95	(0.91)
Sulfur	0.34	0.36	(0.40)
Ash	7.18	7.88	(8.89)
Oxygen (by diff.)	12.61	12.05	(13.89)
Proximate Analysis (percent by weight):			
Moisture	13.76	14.58	(9.21)
Ash	7.18	7.88	(8.89)
Volatile matter	34.88	34.43	(36.57)
Fixed carbon	44.18	43.11	(45.33)
HHV (kJ/kg) (Btu/lb)	24,670 (10,615)	23,910 (10,289)	(24,730) (10,642)

Table F-5. Site B Coal

Test	Baseline	LEA
Ultimate Analyses (percent by weight):		
Moisture	5.66	2.54
Carbon	73.03	75.11
Hydrogen	4.90	4.97
Nitrogen	1.36	1.38
Chlorine	0.07	0.07
Sulfur	0.79	0.81
Ash	6.87	7.48
Oxygen (diff.)	7.32	7.64
Proximate Analyses (percent by weight):		
Moisture	5.66	2.54
Ash	6.87	7.48
Volatile matter	35.17	36.50
Fixed carbon	52.30	53.48
HHV kJ/kg	30,320	31,330
(Btu/lb)	(13,030)	(13,470)
Mineral Analyses	Percent Weight	Ignited Basis
SiO_2 Silica	43.3	50.2
Al_2O_3 Alumina	30.3	33.8
TiO_2 Titania	1.5	1.5
Fe_2O_3 Ferric oxide	12.8	6.6
CaO Lime	2.7	2.4
MgO Magnesia	1.0	1.0
K_2O Potassium oxide	1.8	2.1
Na_2O Sodium oxide	0.9	0.6
SO_3 Sulfur trioxide	3.1	2.1
P_2O_5 Phosphorus pentoxide	0.3	0.4
SrO Strontium oxide	0.1	0.1
Bao Barium oxide	0.3	0.2
Mn_3O_4 Manganese oxide	0.04	0.01

Table F-6. T. H. Wharton Station Gas Turbine Oil

Test	Baseline	Water Injection
Ultimate Analyses (percent by weight):		
Moisture	≤0.01	≤0.01
Ash	0.01	0.005
Carbon	81.98	84.91
Hydrogen	13.16	13.25
Nitrogen	0.11	0.17
Chlorine	0.14	0.13
Sulfur	0.10	0.12
Oxygen (by diff.)	4.5	1.42
HHV kJ/kg (Btu/lb)	46,125 (19,849)	45,897 (19,751)
Specific gravity at 60°F	0.833	0.831

Table F-7. Blueray Oil

Ultimate Analysis	Percent by Weight
Carbon	86.11
Hydrogen	12.90
Nitrogen	0.27
Sulfur	0.19
Ash	<0.01
Oxygen (by diff.)	0.53
High heating value kJ/kg (Btu/lb)	44,768 (9,265)